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Witness: *Keith Majors*
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MISSOURI PUBLIC SERVICE COMMISSION

FINANCIAL AND BUSINESS ANALYSIS DIVISION

AUDITING DEPARTMENT

SURREBUTTAL / TRUE-UP DIRECT TESTIMONY

OF

KEITH MAJORS

EVERGY MISSOURI WEST, INC.,

d/b/a Evergy Missouri West

CASE NO. ER-2024-0189

Jefferson City, Missouri
September 10, 2024

****** Denotes Confidential Information ******

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CASE NO. ER-2024-0189

Q. Please state your name and business address.

A. Keith Majors, Fletcher Daniels Office Building, 615 East 13th Street, Room 201, Kansas City, Missouri, 64106.

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

A. I am a Utility Regulatory Audit Supervisor employed by the Staff ("Staff") of the Missouri Public Service Commission ("Commission").

Q. Are you the same Keith Majors who previously provided testimony in this case?

A. Yes. I provided direct testimony in this case on June 27, 2024, and rebuttal testimony on August 6, 2024.

Q. What is the purpose of your surrebuttal / true-up direct testimony?

A. I will respond to the rebuttal testimony of Evergy Missouri West ("EMW") witnesses Darrin R. Ives, Cody VandeVelde, and Linda J. Nunn concerning the Crossroads Energy Center ("Crossroads") and associated transmission costs, and to witness Buck Reuter concerning Transource and wholesale transmission revenues. I also identify my recommended true-up adjustments in this case.

CROSSROADS

RESPONSE TO WITNESS IVES

Q. On page 25, lines 4-6, Mr. Ives states his opinion that an understanding of the history of Crossroads is not necessary to address the issue going forward. Is he correct?

A. No. I discussed in my rebuttal testimony the retelling of that history from the Commission's perspective in its *Report and Orders* in Case No. ER-2010-0356 ("2010 Rate Case") and Case No. ER-2012-0175 ("2012 Rate Case") and this history is a relevant factor in the current case. I will not repeat that entire history here, other than what is necessary to respond to EMW's rebuttal testimony.

Q. On page 26 of his rebuttal testimony, Mr. Ives refers to "failed management decisions". To what is he referring?

A. This is referring to the years of decisions made by Aquila, Inc. ("Aquila"), EMW's predecessor, since around 1998, that resulted in a deficit in owned generation and a reliance on purchased power. Those decisions can be traced back to Aquila's request to transfer its assets to an affiliated "Exempt Wholesale Generator" ("EWG") in Case No. EM-97-395, and the subsequent focus by Aquila management in investing in non-regulated assets. The series of events driven by Aquila's management decisions were publicly documented in Commission dockets and known to EMW's management when the decision was made to purchase Aquila's assets. In my rebuttal testimony, I focused on Great Plains Energy's ("GPE") decision to include Crossroads in EMW's generating fleet to fill a need for firm dispatchable capacity. The "failed management decisions" relate to Aquila and its predecessors' decisions that led to the need for capacity in the 2007-2008 timeframe that eventually led to the inclusion of Crossroads in EMW's generating fleet. For over a decade during Aquila's ownership, Staff repeatedly and consistently challenged Aquila's reliance on purchased power agreements to meet its capacity and energy needs, and for over half a decade Staff based its determination of Aquila's revenue requirement for its Missouri Public Service ("MPS") division on imputed combustion turbines.

Q. Can you summarize this section of your surrebuttal testimony, responsive to Mr. Ives's comments on "failed management decisions"?

Yes.

- Beginning in the late 1990's Aquila had "a corporate policy not to build regulated generation units"[1]. Therefore, all construction was done by a non-regulated subsidiary with the desire to sell power to regulated operations at market rates.

- Between 1983, with the completion of Jeffrey Unit 3, and 2005, with the completion of South Harper, Aquila, Inc. relied exclusively on purchased power to meet its retail customers' increasing demands for electricity.[2]

- Aquila Merchant constructed the Aries Generating Station as an EWG with a purchased power agreement with MPS, despite being conceived, planned, designed, and engineered by MPS. The Aries Purchase Power Agreement ("PPA") was an affiliate transaction and Staff made adjustments to reduce to a cost-based price.

- Aquila Merchant purchased 18 General Electric 7 EA combustion turbines. Aquila Merchant marketed both the 3 turbines installed at South Harper and the 18 turbines to multiple parties, as opposed to building "steel in the ground" for Missouri customers.

Q. What is the EWG case, Case No. EM-97-395?

A. This case was filed by UtiliCorp United, Inc. ("UtiliCorp")[3] in its anticipation of restructuring and deregulation of the electric industry in Missouri, which never came to

[1] Majors Rebuttal, page 11, Commission *Report and Order*, Case No. ER-2010-0356, page 80.
[2] Ibid.
[3] UtiliCorp United was the parent company of MPS. UtiliCorp would eventually become Aquila, Inc.

fruition. UtiliCorp sought to transfer all generating assets to an affiliate that would own all generation assets and provide service to MPS through market based PPA's.

Q. What is an EWG?

A. An EWG is a non-regulated affiliate of a regulated electric utility that is exclusively in the business of owning or operating, or both owning and operating, all or part of an "eligible facility" and selling electric energy at wholesale. EWG's came into existence as a result of Section 711 of the Electric Policy Act ("EPAct") of 1992 (Section 32(k) of the Public Utility Holding Company Act). Under EPAct, regulated electric utilities are allowed to enter into purchased power agreements with affiliated EWG's as long as certain determinations are made by their state regulatory commissions.

Q. You mentioned Aquila Merchant built the Aries Generating Station as an EWG. What is Aries?

A. Aries is now known as Dogwood, part of which was recently purchased by EMW. It is a 643 MW combined cycle power plant in Pleasant Hill, Missouri. Aries was built as an EWG to initially serve MPS with a 500 MW PPA. Because Aries was in part owned by an MPS affiliate, Case No. EM-99-369 was filed by UtiliCorp in order to obtain the necessary determination from the MPSC regarding the PPA between MPS and MEPPH[4], which was the MPS affiliate who initially owned Aries.

Q. Did Aquila ever consider building Aries as part of its regulated operations?

A. Yes. In 1998, prior to the decision to build Aries by the non-regulated side of Aquila, the regulated operations of MPS considered building a 500-megawatt combined cycle

[4] MEPPH – Merchant Energy Partners Pleasant Hill. An entity jointly owned by an Aquila, Inc. subsidiary and Calpine, an independent third party entity.

unit on the same land that Aries is now on. Because of Aquila's corporate policy to not build regulated generating units, Aquila decided this unit would be a non-regulated non-rate based EWG operating within MPS's service area, with the Aries partners bidding to provide capacity to MPS regulated operations.

In the summer of 1998, at the time of the initial evaluations of the request for proposals for capacity for MPS, which were issued on May 22, 1998, the regulated operations of Aquila responded to its own Request For Proposal ("RFP") with a "build" proposal. This build option to supply capacity and energy to MPS from a combined cycle unit operated by the EWG was the low-cost option at the time of the initial review phase of the RFP.

Q. Why didn't the regulated side of Aquila ("MPS") build the combined cycle unit?

A. The MPS regulated operations of Aquila presented its proposal to Robert K. Green, then Aquila's President, who made the decision that the regulated side of its operations would not build Aries. The material covered two different dates: 1) October 8, 1998, - Financial Analysis of Supply Options, and 2) October 28, 1998, - Updated Analysis of Supply Options. The presentation material was provided to Staff in response to Data Request No. 0301 (Case No. ER-2004-0034).

Generally speaking, the benefit to the utility of developing plants as merchant plants, or EWG's, is that the owners of the plant can seek increased profits from producing energy to sell at market-based rates and not being captive to a state-regulated return. Based on the filing of the EWG case, there was a belief held by Aquila that restructuring with competitive generation would be established in Missouri and that building plants as EWG's avoided the risk of "stranded investment." No other Missouri electric utility developed generating facilities as EWG's to serve Missouri customers and restructuring never came to fruition in Missouri.

Q. Is it Staff's view that Aquila should have given more consideration to building Aries as a regulated unit?

A. Yes. Staff has advocated in numerous cases since 2001 that had Aquila built Aries as a regulated generating station and rate based it in the traditional manner, Aquila likely would not have the capacity issues that created the need for EMW to rely on Crossroads for capacity. Staff has taken issue with Aquila's decision-making regarding building generating units since Aquila's 2001 rate case, Case No. ER-2001-672. In each rate case since the 2001 case through the final Aquila rate cases, Case Nos. ER-2004-0034, ER-2005-0436, and ER-2007-0004, Staff expressed its concerns on the Company's decision not to build generation units and rely on purchase power agreements to meet capacity.

Q. Had Aquila examined building a combined cycle unit as a regulated asset in the past?

A. Yes. In its 1992 Integrated Resource Plan dated February 1992, Aquila (then MPS) identified that its recommendation was to build ** [redacted] ** for MPS.[5]

Q. Did the regulated MPS initially develop the Aries project?

A. Yes. Throughout the late 1990s MPS developed the 500 MW combined-cycle unit that ultimately became Aries, which of course is now known as Dogwood. The site for Aries was land that was previously owned by MPS, the predecessor to UtiliCorp. During the early and mid-1990's, the regulated MPS expended funds to continue to study and develop the preliminary work that was necessary to prepare for construction of this project. Ultimately, Aquila's corporate management determined that the regulated MPS would not be permitted to

[5] February 3, 1992 Integrated Resource Plan-Executive Summary, Item 6.

build the Aries facility but rather its non-regulated Aquila Merchant would develop this project. Aquila Merchant took over the Aries project in the summer of 1998.

Q. After the expiration of the Aries PPA in May 2005, was the PPA renewed?

A. No. Due to dramatic changes in the energy industry and its own deteriorated financial health, Aquila decided to divest itself of its non-regulated assets beginning in mid-2002. ** [redacted] ** The termination of the Aries agreement culminated in a $46.6 million loss[6]. Aquila attempted to buy back Aries in a bankruptcy auction in December 2006, but was unsuccessful.

Not only did Aquila lose a combined cycle unit that should have been constructed as a regulated asset, it lost very valuable land, transmission and natural gas pipeline rights. This facility was sized for additional generating units. ** [redacted] ** The second "Aries II" was to be the three Siemens 501D turbines purchased by Aquila Merchant and stored prior to being installed by Aquila at South Harper. Aquila's decisions to give up its ownership interest in Aries, and going back even further when it decided

[6] Aquila, Inc. 2004 Form 10-K, Dated March 11, 2005.

to get a partner for Aries and construct the plant as an EWG, has caused the Company great hardship in its capacity planning and meeting the energy needs of its customers.

Q. What are examples of some of the other generating plant buying opportunities that Aquila did not take advantage of before 2005?

A. Aquila Merchant purchased 18 General Electric 7 EA combustion turbines. Aquila Merchant installed 4 turbines at Crossroads in Mississippi, 4 at Racoon Creek in Illinois, 6 turbines at Goose Creek in Illinois. Racoon Creek and Goose Creek were sold to Ameren Missouri[7] in 2006 at substantial losses. Three turbines were sold to unaffiliated entities at substantial losses, and the remaining turbine was released back to GE prior to completion, but less a substantial reservation payment. There were many opportunities to have built peaking facilities at very attractive prices in the buyer's market of 2004 when Aquila needed to be preparing to replace by the summer of 2005 the capacity it was losing with the end of the 500 MWs Aries PPA.

Q. Have other Missouri utilities this Commission regulates committed to building power plants, or as it is called, "steel in the ground"?

A. Yes. While Aquila had not built any generating capacity since 1983 with the exception of South Harper, the rest of the electric utilities operating in the state have not followed this path during the time frame in which Aquila made its poor capacity planning decisions. Evergy Missouri Metro ("EMM") installed eight peaking power units at three different locations in Missouri and Kansas, a combined cycle unit and substantially re-built one its coal-fired generating units as the result of an explosion. Liberty Utilities[8] constructed several

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[7] As AmerenUE.
[8] As The Empire District Electric Company ("Empire").

peaking generating units and a large 500 MW combined cycle unit it operates and in which it owns a 60% share (Liberty's share totals 300 MW). Ameren Missouri also committed to building peaking units to meet its regulated system load requirements in Missouri and, as recently as 2002 with Commission approval in Case No. EO-2003-0035, built a regulated unit under a Chapter 100 financing arrangement with the City of Bowling Green, Missouri. This station, Peno Creek, consists of four 47 MW turbines fired by natural gas with fuel oil as a back-up. In addition, in early 2006 Ameren Missouri purchased from Aquila several combustion turbines at two different generating stations located in Illinois called Raccoon Creek and Goose Creek.

Q. Were utilities building their own their generating assets during the same timeframe?

A. Unlike Aquila, the other electric utilities operating in Missouri had a policy of owning their generating assets. While utilities supplement some of their capacity needs with purchase power agreements, they substantially meet their system load requirements by owned and operated assets.

For example, EMM has installed the following generating units over the past several years:

Unit	**Model**	**Unit Size**	**Year Installed**
Hawthorn 6/9[9]	Siemens V-84/GE7EA	227 MW Total	1997-2000
Hawthorn 7	GE 7EA	78 MW	2000
Hawthorn 8	GE 7EA	79 MW	2000
West Gardner 1-4	GE 7EA	311 MW Total	2003
Osawatomie	GE 7EA	77 MW	2003

[9] Hawthorn 6/9 is a combined cycle unit.

EMM also rebuilt the entire boiler and upgraded the steam turbine of its Hawthorn 5 coal-fired base load unit in 2002 to repair damage when the unit experienced an explosion in February 1999.

Similarly, Liberty Utilities (as Empire) has installed the following generating units over the past several years:

Unit	**Model**	**Unit Size**	**Year Installed**
State Line 1	Siemens 501D	96 MW	1995
State Line 2	Siemens F-Model Combined Cycle	300 MW (share of Joint owned units)	2001
Energy Center 3 & 4	Pratt & Whitney	100 MW total	2003

Ameren Missouri has also installed a 48MW turbine at its Venice plant with an installation date of 2002.

Q. These issues span over two decades. Has the Commission evaluated EMW's capacity planning?

A. The Commission discussed and evaluated these issues in the context of the evaluation of GPE seeking to include Crossroads in EMW's generating fleet in the 2010 and 2012 Rate Cases. The *Report and Orders* in those cases discuss some of the litany of poor management decisions and the various detrimental impacts to EMW's ratepayers. For a contemporaneous perspective of how the Commission viewed Aquila's management, I have attached the Concurring Opinion of Chairman Jeff Davis filed in Case No. ER-2007-0004, the final Aquila rate case prior to its acquisition.

Q. What is the significance of this concurring opinion?

A. Chairman Davis' comments stand in contrast to Mr. Ives' suggestion that "it is time to move on", and essentially give EMW a "pass" on the failed management of Aquila and

GPE's decision to use Crossroads in Mississippi to serve Missouri customers. Chairman Davis stated the following in this concurring opinion, attached as Schedule KM-s1:

> 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.

Also of note in this concurring opinion is Chairman Davis' observation that "Aquila is taking steps to add generation capacity by partnering with KCP&L to construct the Iatan II Coal Plant and to construct two new natural gas-fueled electricity-generating turbines in Sedalia, Missouri." As I discussed in my rebuttal testimony, Aquila publicly announced the $152 million 300 MW Sedalia project on April 18, 2007. The Sedalia project would have obviated using Crossroads for EMW's generating fleet in 2008. This project was abruptly abandoned at some point prior to February 29, 2008 when Aquila released its 2007 10-K and noted that the capital budget would be reduced by $186 million for the "new combustion turbine project".

Q. Did the fact that Crossroads is in Mississippi, contrasted with a potential or actual Missouri generating station, factor into the Commission's determination that Crossroads transmission costs should not be recovered?

A. Yes it did. On page 86 of the 2010 Rate Case Report and Order it states:

> 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 cost for power plants located in the MPS district. The annual energy transmission cost was estimated as $406,000 per month. This is also substantially higher on an annual basis than the transmission

> plant costs for the Aries site where the three South Harper Turbines were originally planned to be installed.
>
> 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.
> [footnotes omitted]

In order to fully realize the correct valuation of Crossroads by way of the proxy sales in the 2010 and 2012 Rate Case *Report and Orders*, the Commission should continue to deny recovery of transmission costs. The proxy sales were based on units that were in the purchaser's (Ameren Missouri) Regional Transmission Organization ("RTO"), with no additional transmission costs. To be consistent with both the 2010 and 2012 Commission's orders, the Commission should continue to disallow all transmission costs associated with Crossroads. Both these orders were unanimously voted orders.

Q. On page 26 of his rebuttal testimony, Mr. Ives claims that Crossroads is part of the least cost resource portfolio moving forward. Is looking at Crossroads entirely through the lens of 2024 moving forward appropriate?

A. No, not when applied to Crossroads. The appropriate time frame must capture all the capacity planning decisions looking back to 1998 that created the circumstances at which point Crossroads was included in EMW's generating fleet. Again, I would point to the *Report and Orders* in the 2010 and 2012 Rate Cases for the discussion of the history of Crossroads for a clear and complete picture of the Commission's determinations concerning transmission expense. Relevant sections of those documents were included in my direct and rebuttal testimonies in this case.

Q. On page 25, line 16 of his rebuttal testimony, Mr. Ives postulates that the denial of recovery of Crossroads transmission is a "penalty". Do you agree that EMW has been penalized?

A. No. The valuation adjustment and transmission cost denial are more akin to "ringfencing".

Q. What is "ringfencing"?

A. Ringfencing, in the utility industry, is when a regulated public utility financially separates itself from a parent or affiliate company that engages in non-regulated businesses. In the case of Crossroads, the Commission orders in the 2010 and 2012 Rate Cases insulate rate payers from prior poor planning decisions.

In the distant past, Aquila's financial losses created a situation where in the short and long-term debt capital costs were non-investment grade, commonly referred to as "junk bond" status. To protect its Missouri regulated customers, Aquila proactively recommended that its customers should continue to be charged long and short-term debt costs that reflect representative costs for comparable utilities with a BBB investment. This is not unlike the protections offered to ratepayers through the correct valuation of Crossroads without transmission costs. The Commission should continue to protect ratepayers from Aquila's "failed management decisions", which continue to affect EMW ratepayers.

Q. On page 27 of his rebuttal testimony, Mr. Ives disputes any change in the rate base valuation of Crossroads should the Commission allow any amount of transmission cost recovery. Is a reduced valuation a new concept?

A. No. Staff argued in the 2012, 2016, and 2018 Rate Cases that should the Commission allow any amount of transmission cost recovery, the value of the plant should be reduced to at least the $51.6 million initial valuation found by Aquila and GPE, as discussed in my rebuttal. Depending on the amount of transmission allowed, that valuation could be reduced to $0.

Q. Why is the recovery of transmission cost and the valuation related?

A. The prudence and reasonableness of including Crossroads as a regulated Missouri generating asset and no recovery of transmission costs are inextricably linked. The Commission's justification is on page 99 of the 2010 Report and Order:

> 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.

As determined by the Commission, adding Crossroads to rate base is prudent and reasonable ***only*** if 1) it is included at the fair market value as determined by the Commission, and 2) no recovery of the transmission costs from Mississippi are included. If either qualifier is changed, then Crossroads is not prudent and reasonable to include in EMW's rate base. If the Commission were to find some amount of Crossroads transmission expense should be included in the cost of service, the Commission should find a reduced rate base valuation or a rate base valuation of $0 would be appropriate given the determination of the Commission in the

2010 Rate Case. The 2012 *Report and Order* contemplated the same when the Commission stated: "the value of Crossroads for GMO's MPS rate base shall be $62,609,430 *without transmission cost*."

Based on the Commission's findings, it is critical to the valuation methodology that was used, to exclude transmission expense. The proxy valuation using the actual arms-length transactions between Aquila Merchant and Ameren Missouri actual sale was for combustion turbines located in the same RTO as the customers who the turbines would benefit. The valuation found by the Commission in 2010 and confirmed in 2012 consisted of a valuation package of 1) proxy valuation 2) deferred taxes, and 3) no transmission costs. Otherwise, EMW's actions and Crossroads addition to rate base would be imprudent.

Q. How does EMW's request in this rate case contrast with the requests in prior rate cases?

A. In the 2010 and 2012 Rate Cases, EMW requested the entirety of Crossroads transmission in cost of service. In both the 2016 and 2018 EMW rate cases, EMW requested Crossroads transmission expense in the cost of service, less the amount of disallowed transmission cost that was identified in the 2010 and 2012 Rate Cases of $4.9 million, essentially a "cap" of the disallowance. In both the 2016 and 2018 EMW rate cases, there was no part of EMW's request that would suggest EMW would not renew the transmission service from Crossroads to Missouri regardless of the recovery of transmission costs. Conversely, there was no part of EMW's request in those cases that would suggest an absolute guaranteed renewal of the transmission service if the Commission capped the disallowance or included all transmission costs. Both the 2016 and 2018 Rate Cases were settled by Stipulation and Agreements. In the 2022 Rate Case, EMW did not request any transmission expense for

Crossroads consistent with the 2010 and 2012 Commission orders, but did not concede the issue according to its filed testimony and no mention was made of not renewing transmission service.

Q. In the 2018 Rate Case did EMW appear willing to accept some amount of disallowance and continue to operate Crossroads?

A. Yes. EMW witness Tim M. Rush identified the $4.9 million disallowance as an "equitable allocation of costs" in his rebuttal testimony in Case No. ER-2018-0146:

> **Q: In light of the denial of transmission costs historically, how does GMO justify inclusion in rates of the increase in costs?**
>
> A: The Company's position on the reasonableness of the cost of the Crossroads facility is well documented and is described in the rebuttal testimony of Company witness Crawford. Regardless of the location, the facility remains a low-cost option for providing GMO customers with generation capacity. This would be true even if full recovery was allowed for rate base and transmission costs. Even with the disallowances for rate base and transmission costs ordered in the prior cases, Crossroads continues to provide value to customers. Prior to the increase in transmission costs precipitated by Entergy's entry into MISO ["Midcontinent Independent System Operator"], the Company estimates that GMO customers were paying about $5 million annually for 300 MW of reliable peaking capacity from a diverse source, while GMO shareholders were losing $10 million annually.
>
> **If the Commission accepts the GMO position in this case, the Company will lose about $10 million annually and customers will pay about $12 million annually. This equitable allocation of costs provides customers with energy from a reasonably priced asset whose capacity is fully accredited capacity and with firm transmission to supply energy to GMO customers.** As shown in the Rebuttal Testimony of Company witness Crawford, Crossroads is much more economical than all options, including new construction.
> [Emphasis added.]

EMW proposed what it terms an "equitable allocation" between the shareholders and customers in its rebuttal testimony in the 2018 Rate Case which was at least some compromise, but this is not the solution the Commission determined was fair to customers in the 2010 and 2012 Rate Cases. The Commission found all transmission costs relating to Crossroads should be excluded from rate recovery. What EMW was proposing was not consistent with the Commission's 2010 or 2012 order.

EMW's request in this case is the most adverse to ratepayers compared to the last three rate cases and represents no compromise; EMW is requesting all transmission expense and if the Commission grants anything less, EMW states that it will not renew the transmission service rendering the plant useless to serve Missouri ratepayers.

Q. On page 27 of his rebuttal testimony, Mr. Ives has noted the amounts of disallowed transmission costs that EMW shareholders have absorbed. If the Commission grants EMW's request to include all Crossroads transmission, what will be the impact to customers?

A. It would be astronomical. The current projected retirement date of Crossroads is 2047, for a service life of 45 years. Greenwood Generating Station is comprised of GE 7B turbines, similar to Crossroads 7EA turbines. The current projected retirement date of Greenwood is 2035, which would mean Greenwood Unit 1 would be in service for 60 years. Assuming the compound annual growth rate ("CAGR") of Crossroads transmission expense from 2014 through 2023 of 3%[10], I have calculated the estimated Crossroads transmission expense through the projected retirement date, and a longer service life assuming the 60-year life of the Greenwood turbines. For a base of reference, I have also calculated the cumulative transmission expenses assuming no increases. These amounts would be the minimum amount flowed through rates should the Commission grant EMW's request. I have also added the MISO administrative fees and Federal Energy Regulatory Commission ("FERC") assessments which Staff removed in this and prior rate cases as they are related to Crossroads. The summary is in the table below, I have included the detailed charts as Schedule KM-s2.

[10] *Source*: EMW Direct workpapers.

Base 2024 Transmission:	$16.8 million[11]
MISO Admin Fees and FERC Assessment	$575,186[12]
Total Crossroads Transmission for 2024:	$17.4 million
Cumulative transmission 2025-2047, no increases	$400.3 million
Cumulative transmission 2025-2062, no increases	$661.3 million
Cumulative transmission 2025-2047, 3% CAGR	**$581.7 million**
Cumulative transmission 2025-2062, 3% CAGR	**$1.240 billion**

At a minimum, $400.3 million will be paid by ratepayers if the Commission grants EMW's request. A more realistic outcome will be cumulative transmission expenses of at least $1 billion through the retirement of Crossroads.

Q. On page 29 of his rebuttal testimony, Mr. Ives characterizes Staff, the Office of the Public Counsel ("OPC"), and Midwest Energy Consumers Group ("MECG")'s position on Crossroads as "just say no"? How do you respond?

A. Staff has followed clear Commission guidance from the 2010 and 2012 Rate Cases. Conversely, I would characterize EMW's position on Crossroads as "just say yes" and "let's forget all the bad Aquila decisions" and "just give us a pass on including Crossroads for Missouri generation even though it's over 500 miles away in a transmission constrained area in another RTO". Both Staff and MECG have recommended a reasonable option in this case and in prior cases that should be strongly considered, which is dismantling Crossroads and moving it within the Southwest Power Pool ("SPP") footprint.

Q. On page 31 of his rebuttal testimony, Witness Ives notes that EMW has considered moving Crossroads and the risks involved and transportation costs. How long has EMW considered moving the plant?

[11] Projected 2024 total, Account 565, *Source*: Staff Data Request No. 0097.
[12] Test year 12 Months Ending June 2023.

A. Since at least 2007, according to the documents I attached to my rebuttal testimony. The estimate for moving the turbines at that time was ** [redacted] ** I listed and discussed examples of potential or actual relocations in my rebuttal testimony which I will not repeat here, other than what is necessary to respond to EMW's rebuttal testimony. Since at least the 2016 Rate Case, Staff has recommended that EMW consider relocating Crossroads to within EMW's service territory.

What is troubling is that Aquila studied the possibility of moving the Greenwood turbines due to the expiration of the lease in 1999 in contrast to EMW who heretofore has not seriously considered a relocation of Crossroads. The oldest turbine at Greenwood at that time was 24 years old which is older than the Crossroads turbines are now. On the contrary, EMW's only solution is to force ratepayers to pay upwards of $1 billion of transmission costs that would not be incurred but for Crossroads being over 500 miles away.

Q. Did Aquila consider moving Crossroads?

A. Other than the ** [redacted] ** I am not aware of any specific study or estimate to move Crossroads. Aquila did consider moving the Racoon and Goose Creek turbines, which were already installed, in December of 2005. I have attached a memorandum which has a high-level analysis of moving the Racoon and Goose Creek turbines to Missouri versus purchasing new turbines and with installation, as Confidential Schedule KM-s3. This is the response to Staff Data Request No. 0355 in Case No. ER-2007-0004. This analysis noted estimated site removal costs per the South Harper dismantlement study[13] of ** [redacted]

[13] This study is attached to my rebuttal testimony.

[redacted] **. Goose Creek is in Piatt County, Illinois, roughly 375 miles from EMW headquarters. Raccoon Creek is in Clay County, Illinois, roughly 350 miles from EMW headquarters compared to Crossroads which is 525 miles away.

Q. Are there potential sites that could accommodate the Crossroads turbines?

A. Yes. I noted several sites that were considered by EMW or EMM at various times in the last 20 years in my rebuttal testimony. I have attached as Confidential Schedule KM-s4 the response to Staff Data Request No. 0002 in Case No. EA-2005-0248. This document lists additional alternate sites that were considered for the three Siemens 501D turbines that were installed at South Harper. These additional sites may still be viable, but this document is nearly 20 years old.

Q. Staff's recommendation that EMW should consider moving the Crossroads turbines would appear to some as efforts to directly manage the utility. Do you believe that to be the case?

A. No. EMW has presented the Commission with a problem. Its only recommended solution is to foist upwards of $1 billion on its Missouri customers through 2062. Staff has presented the Commission, and EMW, a viable alternative to outright abandoning Crossroads and leaving customers bereft of capacity or building new generation at substantially higher costs. Crossroads should be relocated but EMW will never explore this viable solution if the Commission allows any recovery of transmission costs.

RESPONSE TO WITNESS VANDEVELDE

Q. On pages 4-5 of his rebuttal testimony, Mr. VandeVelde notes the claimed benefit of Crossroads' location, specifically during Winter Storm Uri (February 2021) and

Elliot (December 2022). Was EMW able to use its Missouri gas fired generation during these events?

A. Yes, and so was EMM. Natural gas is generally available throughout the year. Mr. VandeVelde notes two events; I would add the "polar vortex" in January-February 2014.

In this winter event, Greenwood and Crossroads both were able to produce electricity from gas-fired generation:

**

[redacted]	[redacted]	[redacted][14]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	

**

Clearly, Crossroads generated greater megawatt-hours than Greenwood at a higher gas cost, but Greenwood had natural gas available to produce needed electricity during this extreme and unusual weather pattern.

EMM had natural gas available in Kansas City to operate its natural gas fired units to generate electricity during the same time frame.

Month (2014)	**Osawatomie MWhs**	**West Gardner 1-4 MWhs**
January	2,308	365
February	1,112	0
Total	3,420 MWhs	365 MWhs

[14] The abbreviation for one million British thermal units, the consumable unit of natural gas ("mmbtu").

Q. In his rebuttal testimony, Mr. VandeVelde notes the impact of Winter Storm Uri. Was Crossroads the only EMW unit available during this time?

A. No. Using the availability data in Staff Data Request No. 0054, Crossroads, Greenwood, and South Harper were available for both day-ahead and real-time for energy during some of the hours of Winter Storm Uri[15]:

**

[redacted][16]		[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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	[redacted]	[redacted]	[redacted]	[redacted]

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[15] Defined as February 10-19, 2021, Darrin R. Ives Direct testimony, Case No. EF-2022-0155, 10 days totaling 240 hours. No data was included for the Day Ahead for February 17.
[16] Not inclusive of any ancillary service availability.
[17] Not inclusive of any ancillary service availability.
[18] Not inclusive of any ancillary service availability.

Q. In his rebuttal testimony, Mr. VandeVelde notes the impact of Winter Storm Elliot. Was Crossroads the only EMW unit available during this time?

A. No. Using the availability data in Staff Data Request No. 0054, Crossroads, Greenwood, and South Harper were available for both day-ahead and real-time for energy during some of the hours of Winter Storm Elliot[19].

**

[redacted] [20]		[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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[redacted] [21]		[redacted]	[redacted]	[redacted]
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[19] FERC Defines Winter Storm Elliot as December 21-26, 2022, 6 days totaling 144 hours.
[20] Not inclusive of any ancillary service availability.
[21] Not inclusive of any ancillary service availability.
[22] Not inclusive of any ancillary service availability.

Q. On pages 5-6 of his rebuttal testimony, Mr. VandeVelde notes the lower marginal price of gas at Crossroads. What have been the actual gas costs experienced by Crossroads in comparison to other EMW units?

A. Historically, the Mississippi-based Crossroads has experienced higher natural gas costs when compared to natural gas prices and costs in and about Kansas City, Missouri. The data I am using is actual gas costs from the responses to Staff Data Request No. 0070 from this and prior rate cases.

Specifically, Crossroads natural gas prices have been higher than those for EMW's South Harper and Greenwood in most years. The following table compares Crossroads natural gas costs with those at both South Harper and at Greenwood (for a detailed summary of natural gas costs for these generating facilities see Confidential Schedule KM-s5):

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[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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Source: EMW Data Request No. 0070, Case No. ER-2024-0189, GMO Data Request No. 0070, Case No. ER-2016-0156; GMO Data Request Nos. 0070 and 0070.1, Case No. ER-2012-0175 and GMO Data Request Nos. 0070 and 0070.1, Case No. ER-2010-0356

[23] Through June 2024.

It is only when firm transportation costs (the pipeline reservation payments) are included that South Harper has higher total natural gas costs than Crossroads. These costs are significant because the pipeline reservation costs are high in relation to the relative low generation from this plant which inflates the per mmbtu unit costs. In every year since 2009 South Harper actual natural gas commodity costs are lower than those for Crossroads except 2015 and 2020, and even when the variable transportation costs are included with the commodity charges, the delivered gas price, South Harper is still lower than Crossroads except for in 2011, 2020, and 2022.

Of particular note, Greenwood has significantly lower natural gas commodity costs than Crossroads in every year from 2009 to 2024 and, when variable transportation costs are considered, Greenwood variable fuel costs are lower than Crossroads in each year from 2009 with exception of 2011 and 2013. When all costs are considered, Greenwood fuel costs are less than Crossroads in most years. Through June 2024, Crossroads delivered natural gas cost is more than twice that of Greenwood, and Greenwood has burned **[redacted] ** versus Crossroads at ** [redacted] ** during the same timeframe. Greenwood does not need firm transportation for natural gas because it is capable of using oil as a backup fuel source.

Equally important, the higher natural gas prices at Crossroads are consistent with the higher transmission costs to transport the energy from Crossroads back to Kansas City to serve EMW's customers. Greenwood and South Harper, both located in Kansas City area, do not cause EMW to incur any additional transmission costs to transport electricity from them to EMW customers.

When evaluating these historical prices, it is important to note that firm transportation costs are "sunk costs" which are incurred regardless of the gas burned. The variable commodity costs with variable transportation are more relevant to the economy of operating the unit as the variable gas costs are the largest variable operating cost.

Q. What is the cost of firm gas transportation costs at South Harper?

A. In contrast to transmission costs at Crossroads, firm gas transportation costs have fluctuated little from 2009 through the present. To support the 315 MW at South Harper, EMW has incurred an average of ** [redacted] ** of firm gas transportation costs from 2009 through 2023, and the current costs are ** [redacted] ** annually.

Not all peaking units owned by EMW or EMM incur firm transportation costs. Greenwood has massive oil tanks used for fuel when natural gas is unavailable.

Q. On page 8 of his rebuttal testimony, Mr. VandeVelde notes that the Plum Point Generating Station owned by Liberty Utilities ("Liberty") is in MISO's footprint and that Liberty incurs MISO transmission costs and recovers those costs through rates. Why is Plum Point different?

A. I outlined the differences in my rebuttal testimony. In summary, Crossroads is used far less than Plum Point, so the transmission costs per MWH is substantially higher for Crossroads than Plum Point. Mr. VandeVelde notes former Staff auditor Cary G. Featherstone's testimony in the 2016 Rate Case, and Mr. Featherstone's noted distinctions between Plum Point and Crossroads. All of Mr. Featherstone's noted differences, which were also discussed in my rebuttal testimony, are valid and remain unrefuted by Mr. VandeVelde. Simply put, Plum Point and Crossroads is an apples-to-oranges comparison as I will explain further.

Q. What are Plum Point's generation and transmission costs in relation to the MWH's produced compared to Crossroads?

A. Below is a table that identifies Plum Point's levels of generation by year since its operations began in 2010. Crossroads and Plum Point pay the same rate under the MISO tariff for service.[24] Included in this table are the transmission costs by year incurred by Empire to transmit power back to Empire's service area:

**

[redacted]	[redacted] [25]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]

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Source: Liberty Electric Case No. ER-2016-0023 Data Request Nos. 0108 and 0196, Case No. EO-2018-0244 Data Request No. 0063, Generation Data Filed on EFIS.

[24] EMW witness Burton L. Crawford Surrebuttal Testimony, page 2, Case No. ER-2016-0156.

[25] Staff does not have Plum Point specific MISO transmission cost data from 2018 through 2023. The transmission expenses have been estimated based on the average of 2017-2014 Plum Point transmission increased by the Crossroads transmission CAGR of 3%.

As a peaking unit, Crossroads is used far less and the transmission cost per MWH is far greater:

Year	Transmission Costs[26]	Net Generation MWhs	Transmission Costs per MWh
2023	$15,709,528	208,365	$75.39
2022	$16,973,509	196,525	$86.37
2021	$14,833,678	75,175	$197.32
2020	$12,624,032	118,549	$106.49
2019	$11,523,158	126,745	$90.92
2018	$10,690,227	64,471	$165.81
2017	$11,356,162	12,353	$919.30
2016	$12,282,484[27]	23,261	$528.03
2015	$12,467,975	19,992	$623.65
2014 (Entergy in MISO)	$12,247,388	70,616	$173.44
2013	$4,323,166	44,559	$97.02
2012	$3,690,572	84,865	$43.49
2011	$4,747,065	88,681	$53.53
2010	$4,744,507	23,719	$200.03

Q. Using the projections of transmission costs detailed earlier in your testimony, how much will transmission costs be per MWH in the future?

A. Using a net capacity factor of ** [redacted] ** projects ** [redacted]** MWH of annual generation[28].

[26] Account 565 costs only, does not include additional transmission costs of MISO administration fees and MISO FERC assessment.
[27] Does not include a one-time MISO resettlement and rate adjustment.
[28] As used in Mr. VandeVelde's Crossroads Capacity Model.

Year	Crossroads Transmission Costs	Crossroads Projected Generation	Crossroads Transmission Costs per MWh
2024 (Base)	$17,402,679	** [redacted] **	** [redacted] **
2047 (Projected Retirement)	$34,345,692	** [redacted] **	** [redacted] **
2062 (60 year life)	$53,509,469	** [redacted] **	** [redacted] **

Q. On page 10 of his rebuttal testimony, Mr. VandeVelde claims that the difference between Plum Point and Crossroads is irrelevant. How do you respond?

A. Plum Point is a 665 MW coal-fired generating station designed to run when available, sometimes 24 hours per day. Crossroads is a 300 MW natural gas fired peaking unit designed to run sporadically during peak demand. The net capacity factor used by Mr. VandeVelde for his analysis to justify Crossroads is only ** [redacted] **. The difference could not be clearer. I know of no other utility that has a peaking plant in another RTO and is paying such high transmission costs.

Dogwood Energy, LLC, who had consistently intervened in EMW's rate cases, filed testimony that no other utility sites combustion turbines so far from the utility's load center:

> **Q. WHAT IS THE MOST DISTANT GMO UNIT AT THIS TIME?**
>
> A. The most distant GMO unit, the Nevada unit, is approximately 108 miles from GMO's load center (see Schedule JLR-1). The average distance of GMO units, excluding Crossroads, to the load center (Kansas City) is 69 miles. In contrast, and as noted, Crossroads is roughly 400 miles away.
>
> **Q. ARE YOU AWARE OF ANY OTHER COMBUSTION TURBINE PEAKING PLANTS IN THE UNITED STATES LOCATED SO FAR FROM THE UTILITY LOAD CENTER.**
>
> A. No.[29]

[29] Dogwood Energy, LLC witness Judah Rose Surrebuttal, page 28, Case No. ER-2009-0090.

Q. Is there another example of a utility owning base-load generation outside of its RTO?

A. Yes. Columbia Water and Light (“CWL”) in Columbia, Missouri has a PPA for 20 MW of Iatan 2 for its operational life, not unlike Liberty’s ownership and PPA with Plum Point. CWL is a member of MISO and Iatan 2 is in SPP. CWL pays SPP for point-to-point transmission service for the capacity and energy of Iatan 2. Like Plum Point, Iatan 2 is a baseload coal unit that operates much more than any combustion turbine owned by EMW; thus, the economics of incurring substantial transmission costs for this resource are justified. The justification would be even greater for Iatan 2 in that its boiler is of a supercritical design with a lower heat rate than Plum Point’s sub-critical design; thus, Iatan 2 is more efficient.

Q. Is EMW’s recommendation concerning Crossroads transmission the same as prior rate cases?

A. No, in fact EMW’s position is the most detrimental for its customers since the 2012 Rate Case. In the 2012 Rate Case, EMW requested the full amount of transmission expense which at that time was $4.9 million. In the 2016 Rate Case, EMW sought transmission expense over the 2012 disallowance, resulting in $8.2 million included in rates. In the 2018 Rate Case EMW sought transmission expense over the 2012 disallowance, resulting in $6.4 million included in rates. In the 2022 Rate Case, EMW sought $0 of Crossroads transmission expense.

Q. Please summarize your surrebuttal testimony concerning Crossroads.

A. The Commission should affirm no recovery of Crossroads transmission expenses. It is not reasonable to flow over $1 billion of transmission expenses to ratepayers.

Staff has presented the viable alternative of relocating Crossroads to the SPP footprint and EMW should investigate this alternative.

RESPONSE TO WITNESS NUNN

Q. On page 9 of her rebuttal testimony, Ms. Nunn states that the FERC regulatory assessments related to Crossroads have not been identified in prior rate cases. Do you agree?

A. No. Staff has removed both the FERC assessment related to Crossroads' location in the MISO RTO as well as the MISO administrative fees in the 2016, 2018, and 2022 rate case, and the current rate case. The FERC assessment and MISO administrative fees are billed to EMW through MISO. But for Crossroads being located in the MISO RTO, EMW would not incur these expenses. Staff has properly removed these costs in addition to the point-to-point transmission costs recorded in FERC Account 565 in accordance to the 2010 and 2012 Commission orders concerning Crossroads transmission.

<u>TRANSOURCE</u>

RESPONSE TO WITNESS REUTER

Q. On page 1 of his rebuttal testimony, Mr. Reuter identifies that Staff did not use actual rates and inputs for years 2018 through 2023 in the calculation of this adjustment. Is that correct?

A. Yes, but that does not impact the calculations for 2024.

Q. Please explain.

A. First, an explanation of what this adjustment is intended to accomplish is necessary, followed by an explanation of how it works. I explained some of the history of Transource and this adjustment in my direct testimony filed in this case.

Transource Missouri is a subsidiary of Evergy, Inc., that partnered with American Electric Power Company, Inc., to construct transmission infrastructure in SPP, as well as in other RTOs. In Case Nos. EA-2013-0098 and EO-2012-0367, EMW and EMM sought to transfer, or "novate" to Transource Missouri the rights to construct and operate two high-voltage transmission projects. SPP directed then KCP&L and GMO to construct two regionally beneficial transmission projects, known as the Iatan-Nashua 345 kV transmission project ("Iatan- Nashua Project") and the Sibley-Nebraska City 345 kV transmission project ("Sibley- Nebraska City Project") (collectively the "Projects"). The Iatan-Nashua Project is one of the seven (7) SPP regional "Balanced Portfolio" projects, which were approved by SPP in 2009. The Sibley-Nebraska City Project is one of the six (6) SPP regional "Priority Projects," which were approved by SPP in 2010. At the time, KCP&L and GMO were Designated Transmission Owners ("DTOs") and were issued Notices to Construct ("NTC") for portions of the Iatan-Nashua Project, and GMO was issued an NTC for its responsibility of the Sibley-Nebraska City Project.

Q. What was the result of those cases?

A. The Commission authorized the transfer to Transource Missouri of the rights to build the projects. As part of the *Non-Unanimous Stipulation and Agreement* in those cases, and as included in the *Report and Order* by the Commission, the Commission ordered adjustments to be made to the transmission expenses included in the then KCPL and GMO rate cases for as long as the two transmission facilities are in service. These adjustments were to be made in perpetuity as these facilities are permanent transmission facilities. These adjustments were intended to insulate EMW and EMM customers from FERC transmission rate incentives that typically increase the cost allocation to regulated utilities as compared to ratemaking under traditional ratemaking principles.

Q. What are FERC incentives?

A. FERC incentives are authorized changes to the cost-based ratemaking included in a Transmission Owner's Annual Transmission Revenue Requirement ("ATRR"). Transource Missouri received the following incentives:

- 100 basis point ROE Risk Adder for the Sibley-Nebraska City Project to address the financial risks and regional benefits associated with the project;
- inclusion of 100% of CWIP in rate base during the development and construction periods for each of the Projects;
- deferral of all prudently-incurred costs that are not capitalized prior to the rates going into effect for recovery in future rates;
- use of a hypothetical capital structure consisting of 40% debt and 60% equity during construction until long-term financing is in place for both Projects; and
- recovery of prudently-incurred costs in the event either of the Projects must be abandoned for reasons outside the reasonable control of Transource Missouri.

These incentives would have been unavailable to EMW and EMM in their Missouri regulated rates if they had built the projects. Also of note is that EMW and EMM would have received increased revenues if the projects were retained by the regulated utility.

Q. How are the adjustments calculated to insulate EMW ratepayers?

A. I used the same methodology and calculation model that was developed by Don Frerking, who at that time was employed by EMM, in the 2014 EMW rate case, Case No. ER-2014-0370, although EMM witness Ronald A. Klote sponsored the adjustment. This same model has been used by EMW, EMM, and Staff in the 2014 EMM rate case, the 2016 EMM and EMW rate cases, the 2018 EMM and EMW rate cases, and the 2022 EMM and EMW rate cases. In the current rate case, I asked for the supporting calculations from EMW in Staff Data Request No. 0411. EMW did not provide the model that has been used for the last several rate cases, but did provide updated inputs for the calculations which I used in the last case's model. I then updated the 2024 ATRR calculations as that is the most updated available.

The adjustment uses the Transource ATRR inputs for capital structure, cost of debt, and plant and reserve, and other various inputs, and compares that revenue requirement for the two projects to the revenue requirement using traditional Missouri Public Service Commission ratemaking methods, including Staff's recommended capital structure, return on equity, actual cost of debt, etc. Finally, the most updated load ratio-share for EMW is used to allocate the amount that is actually billed to EMW.

Q. On pages 2-3 of his rebuttal testimony, Mr. Reuter points out that Staff did not update the calculations for actual ATRR inputs for 2018-2023, and that all the inputs should be updated for those years. Do the prior years need to be updated?

A. No. Staff's adjustment, and EMW's adjustments in prior cases, depend on the most current year's ATRR to determine the adjustment. The prior year's calculations do not factor into the adjustment and therefore do not need to be updated.

In prior rate cases, both Staff and EMW have used the most recently available ATRR to calculate the differences:

EMW Case No.	**ATRR Year**	**Company Adjustment**	**Staff Adjustment**
ER-2016-0156	2016	($950,475)	($1,006,044)
ER-2018-0146	2018	$119,310	($88,344)
ER-2022-0130	2022	$20,517	($42,941)

In the current rate case, Staff calculated an adjustment of ($2,999), and EMW calculated an adjustment of $85,681.

Q. Why have the adjustments been different?

A. There have been various disagreements between Staff and EMW over what constitutes a FERC incentive or a difference in ratemaking methodology between the Transource ATRR and the hypothetical EMW ATRR if the projects had been built by the regulated utility.

Q. The adjustment's materiality, regardless of EMW or Staff calculations, has decreased over time. Why is that?

A. The hypothetical capital structure was a temporary incentive authorized until permanent financing was placed. The regulatory asset for pre-commercial costs was amortized over five years following the projects' completion and is now fully amortized. The depreciation reserve continues to build reducing the return on rate base. In the near future, these changes will continue to narrow the gap between the Transource ATRR and the EMW ATRR and no changes will take place that would alter that trend.

Q. On page 4 of his rebuttal testimony, Mr. Reuter recommends eliminating this adjustment from this case and any future cases. Do you agree?

A. I do not disagree that this adjustment has become immaterial. The more relevant reason to stop calculating the adjustment is that the inputs are somewhat subjective rather than the adjustment is complicated, especially given that EMW created the adjustment methodology and has used it for the last 10 years. The roadblock I see is that the parties to the *Stipulation and Agreements* agreed to the adjustments in principle, not on the specific methodology, for as long as the projects are in service. The Commission approved the stipulations and ordered those adjustments. Other than Staff, the only other non-utility parties to the Stipulation and Agreement were Transource Missouri, who I assume has no interest in this adjustment, and OPC.

WHOLESALE REVENUE CREDIT

Q. On pages 4-6 of his rebuttal testimony, Mr. Reuter suggests that EMW's R-80 adjustment is needed to correct an improper arbitrage situation where ratepayers are improperly profiting from EMW's transmission assets. What is your response?

A. EMW has recommended this adjustment since at least the 2012 rate case. Staff has consistently disagreed with the adjustment since the 2016 rate case; this is a solution looking for a problem.

Q. Please summarize Staff's recommendation regarding wholesale transmission revenue.

A. EMW is billed transmission expense from SPP as a transmission customer and receives transmission revenues from SPP as a Transmission Owner, both of which include Return on Equity ("ROE") incentives, in this case, a 50 basis point ROE adder for being a member of an RTO. Staff recommends that EMW treat transmission expense and revenue consistently by reflecting all of EMW's revenue and expense, including the impact of Federal Energy Regulatory Commission ("FERC") ROE incentives, in its cost of service.

Q. How does Staff respond to Mr. Reuter's statement in his rebuttal testimony, respecting a Staff adjustment, on page 5, lines 20-21, that, "Essentially Missouri retail customers would be credited back more than they would have been charged"?

A. Mr. Reuter argues that since all of EMW's transmission assets are included in the retail revenue requirement based on a Commission authorized ROE, and transmission revenues received from SPP are based on a higher FERC ROE, an adjustment must be made to reduce revenues; otherwise, according to Mr. Reuter, EMW's Missouri retail customers would be credited back more than they have been charged. Staff disagrees that this crediting is in any way improper. EMW's participation in SPP encompasses both the financial impacts of EMW's ownership of transmission assets and the financial impacts of the use of other SPP members' transmission assets. As a SPP transmission customer, if costs of providing transmission service increase for other members of SPP, EMW's transmission expense will increase. Likewise, as an SPP Transmission Owner, if EMW's cost to provide transmission service increases, transmission revenues received from SPP will increase. Staff considers both transmission revenue and transmission expense incurred by EMW as costs of doing business and, as such, should be reflected in EMW's cost of service on a consistent basis.

Q. On page 7 of his rebuttal testimony, Mr. Reuter notes the only FERC incentive currently being earned is the 50 basis point adder for EMW being a member of an RTO. Who pays for RTO membership?

A. Customers do, as all these expenses are passed through in the cost of service. All SPP administrative fees, all internal labor, and all expenses related to EMW's status as a Transmission Owner in the SPP are included in customer rates. It only makes sense that whatever transmission revenues can be earned by EMW should be included at the full amount to defray these expenses.

Q. What is a "Transmission Owner?"

A. Based on SPP's Open Access Transmission Tariff, a Transmission Owner, as a member of SPP, is an entity that is obligated to construct, own, operate, and maintain transmission facilities as directed by SPP. SPP utilizes EMM's and EMW's annual ATRR to allocate revenues to Transmission Owners and expenses to Transmission Customers. Transmission revenues are collected from SPP Transmission Customers for the amount necessary to recover the revenue requirement for the Transmission Owners.

Q. Is EMW charged by SPP on behalf of other Transmission Owners that are members of SPP?

A. Yes. Other Transmission Owners of SPP receive an authorized FERC ROE that may include FERC ratemaking incentives and ROE adders. As Transmission Customers of SPP, EMM and EMW are charged their allocated share of transmission expense by SPP for other Transmission Owners of SPP that have constructed, upgraded, and maintained transmission infrastructure. The allocated transmission expense charged to EMM and EMW includes approved FERC ratemaking incentives and adders for other SPP members.

Q. How do customers pay for EMW's transmission expenses?

A. Through the cost of service. In Staff's direct filing, Staff included $34.0 million of transmission operation and maintenance expenses, $818.6 million in net plant which would also earn EMW a rate of return, and $21.8 million of depreciation expense. Customers have paid and will continue to pay these costs.

EMW receives the revenues in question that partially defray these expenses through the ATRR, and a normalized amount of those revenues of $3.1 million were properly included in the cost of service and defray the substantial costs paid by customers. EMW's proposed adjustment removes $168,830 of these revenues.

Q. What are other examples of revenue, or other reductions to expense that EMM and EMW receive as utilities?

A. Some examples are wholesale revenues, off-system sales revenues, and insurance proceeds. These revenues or reductions in cost are appropriately reflected in customer rates with no adjustment. The analogy of transmission revenues to wholesale and off-system revenues are that wholesale and off-system revenues are not retail revenues, but are revenues received by EMM and EMW for non-retail electricity at rates governed by FERC or on the open market. Off-system sales revenues, generally, are non-firm electricity sales above the amount used for native load. Prior to the SPP "Day 2 market,"[30] the Commission included a normalized level of off-system sales margin revenue similar to the inclusion of transmission revenue.

EMM and EMW have never claimed that receipt of these revenues unjustly reduced rates for customers nor have they recommended an adjustment for the return on equity realized from these transactions. Like its transmission assets, customer pay for all the rate base, fuel, and operations and maintenance expense that enable EMW to sell excess electricity and likewise all revenues should be considered in the ratemaking process.

Q. How did Staff treat EMW's transmission expense in this case?

A. Staff included an annualized level of transmission expense based on the 12-month period ending June 30, 2024 as of the true-up date in this case. With the exception of adjustments made for Transource Missouri incentives and transmission expense related to EMW's Crossroads facility, Staff did not eliminate any transmission expense.

[30] Currently, EMW and EMM "sell" all their energy to SPP and "buy" their native load obligations. The residual that is sold into the SPP market is comparable to that which was referred to as "non-firm off system sales." This residual impacts the cost of service in the same manner as inclusion of non-firm off system sales.

TRUE-UP ADJUSTMENTS

Q. Please identify the rate base items that you have updated with true-up data through June 30, 2024.

A. I have updated the rate base balance of Crossroads net of the valuation reduction pursuant to the 2010 and 2012 Rate Case orders. I have also included plant additions of EMW's purchase of the Dogwood Energy Facility. The Iatan regulatory assets were also updated through June 30.

Q. Did you update any adjustments to the income statement for true-up?

A. Yes. I updated the Staff adjustments for plant amortization and prospective regulatory asset and liability tracking. I have included the impact of the Dogwood purchase including operations and maintenance expense and capacity revenues.

Q. Are any of the methodologies you used in your true-up adjustments different from your direct adjustments?

A. Yes. The purchase of Dogwood was not finalized until June 2024 so no methodology was established in Staff's direct filing. Staff's methodology for the Dogwood adjustments is substantially the same as other similar ratemaking items.

Q. Does this conclude your Surrebuttal / True-up Direct testimony?

A. Yes it does.

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 KEITH MAJORS

STATE OF MISSOURI)
) ss.
COUNTY OF Jackson)

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Surrebuttal / True-Up Direct Testimony of Keith Majors*; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors
KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 9th day of September 2024.

CHERYL LEVERETTE
MY COMMISSION EXPIRES 9-7-2027
NOTARY SEAL
#01404338
JACKSON COUNTY
NOTARY PUBLIC, STATE OF MISSOURI

Cheryl Leverette
Notary Public

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 Iatan 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 Iatan 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.

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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.

Projected Crossroads Transmission
Prepared by Keith Majors

Base Transmission	16,827,493
MISO Admin Fees and FERC Assessn	575,186
Total Base	17,402,679

	Assume 3% CAGR 2014-2023	No Increase
2024	17,402,679	17,402,679
2025	17,924,759	17,402,679
2026	18,462,502	17,402,679
2027	19,016,377	17,402,679
2028	19,586,868	17,402,679
2029	20,174,474	17,402,679
2030	20,779,709	17,402,679
2031	21,403,100	17,402,679
2032	22,045,193	17,402,679
2033	22,706,549	17,402,679
2034	23,387,745	17,402,679
2035	24,089,378	17,402,679
2036	24,812,059	17,402,679
2037	25,556,421	17,402,679
2038	26,323,113	17,402,679
2039	27,112,807	17,402,679
2040	27,926,191	17,402,679
2041	28,763,977	17,402,679
2042	29,626,896	17,402,679
2043	30,515,703	17,402,679
2044	31,431,174	17,402,679
2045	32,374,109	17,402,679
2046	33,345,332	17,402,679
2047	34,345,692	17,402,679
2048	35,376,063	17,402,679
2049	36,437,345	17,402,679
2050	37,530,465	17,402,679
2051	38,656,379	17,402,679
2052	39,816,071	17,402,679
2053	41,010,553	17,402,679
2054	42,240,869	17,402,679
2055	43,508,095	17,402,679
2056	44,813,338	17,402,679
2057	46,157,738	17,402,679
2058	47,542,471	17,402,679
2059	48,968,745	17,402,679
2060	50,437,807	17,402,679
2061	51,950,941	17,402,679
2062	53,509,469	17,402,679
2025 Through 2047 Retirement	581,710,126	400,261,613
2025 Through 2062 Retirement	1,239,666,476	661,301,796

Case No. ER-2024-0189

SCHEDULE KM-s3,

SCHEDULE KM-s4,

and

SCHEDULE KM-s5

HAVE BEEN DEEMED

CONFIDENTIAL

IN THEIR ENTIRETY