Exhibit No.:	_______________
Issue(s):	Customer Experience/ Stranded Asset/T&D Investments/CCOS/Rate Design
Witness/Type of Exhibit:	Marke/Rebuttal
Sponsoring Party:	Public Counsel
Case No.:	ER-2021-0312

REBUTTAL TESTIMONY

OF

GEOFF MARKE

Submitted on Behalf of the Office of the Public Counsel

THE EMPIRE DISTRICT ELECTRIC COMPANY D/B/A LIBERTY

FILE NO. ER-2021-0312

*** ***

Denotes Confidential Information that has been redacted

December 20, 2021

PUBLIC

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	))))))	Case No. ER-2021-0312

AFFIDAVIT OF GEOFF MARKE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Geoff Marke, of lawful age and being first duly sworn, deposes and states:

1. My name is Geoff Marke. I am a Chief Economist for the Office of the Public Counsel.

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

Geoff Marke
Chief Economist

Subscribed and sworn to me this 20th day of December 2021.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
TIFFANY HILDEBRAND
My Commission Expires
August 8, 2023
Cole County
Commission #15637121

Tiffany Hildebrand
Notary Public

My Commission expires August 8, 2023.

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REBUTTAL TESTIMONY

OF

GEOFF MARKE

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2021-0312

I. INTRODUCTION

Q. Please state your name, title, and business address

A. Geoff Marke, PhD, Chief Economist, Office of the Public Counsel (OPC or Public Counsel), P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Dr. Marke that filed direct testimony revenue requirement in ER-2021-0312?

A. I am.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the direct testimony of other parties' witnesses on select topics. The following is a list of those topics and the witnesses:

- The Lens of the Customer
  - Empire witness Timothy N. Wilson
- Asbury Stranded Asset
  - Empire witnesses Frank C. Graves;
  - Missouri Public Service Commission Staff ("Staff") witness Mark L. Oligschlaeger; and
  - Midwest Energy Consumers Group ("MECG") witness Greg R. Meyer
- Transmission and Distribution Investments
  - Empire witnesses Jeffrey Westfall, Chad C. Hook and Tisha Sanderson
- Class Cost of Service Studies
  - Empire witness Timothy S. Lyons;
  - MECG witness Kavita Maini; and
  - Staff witness Cedric E. Cunigan

- Rate Design
    - Empire witness Gregory W. Tillman; and
    - Staff witnesses Cedric E. Cunigan, Sarah Lange and Amanda Coffer

My silence regarding any issue should not be construed as an endorsement of, agreement with, or consent to any witness' testimony or any party's filed position.

II. THE LENS OF THE CUSTOMER

Response to Mr. Wilson

Q. How did Mr. Wilson frame his "Overview of the Case"?

A. Very positively. Mr. Wilson cites to three fundamental objectives:

- Sharing of benefits of new technology with customers;
- Making good on Commission guidance from the last rate case; and
- Responsibly managing Winter Storm Uri costs

He said that Empire relied on the following underlying fundamental principle, which he described as:

> Empire approached this case through the lens of the customer. As you will note throughout this testimony, Empire applied multiple levers available to reduce the impact of this filing on its customers.[1]

I will respond to each of these in turn.

Q. How do Empire's customers compare to other Missouri investor-owned utility customers?

A. Empire's customer's currently pay higher total retail average rates (in cents/kilowatt-hour) than the rest of Missouri's IOU customers according to the Edison Electric Institute's (EEI) "Typical Bills and Average Rates Report" summer 2020 as seen in Table 1:

[1] Case No. ER-2021-0312, Direct Testimony of Tim N. Wilson p. 7, 7-9.

Table 1: EEI's 2020 Missouri Total Retail Average Rates[2]

Missouri	**2020**
Ameren Missouri	8.44
Empire	11.51
Evergy West	9.71
Evergy Metro	10.73
Average for Missouri IOU	9.23
Average for Missouri w/ munis, coops, etc…	9.63 (2019)

EEI's findings are largely consistent with what was reported year end in the U.S. Energy Information Agency's (EIA) Form 861 filing as shown in Table 2 below.

Table 2: EIA's Missouri IOU Residential Customer, Revenues, Usage, and Avg. per month[3]

	Res. Customers	Res. Revenues	Res. Sales kWh	Avg. Monthly Bill	Avg. Monthly Usage kWh
Empire	133,019	$220,750,600	1,644,537,000	$138.30	1,030
Metro	262,729	$350,024,100	2,608,047,000	$111.02	827
West	291,923	$402,216,600	3,561,621,000	$114.82	1,016
Ameren	1,071,999	$1,371,554,300	13,250,393,000	$106.62	1,030

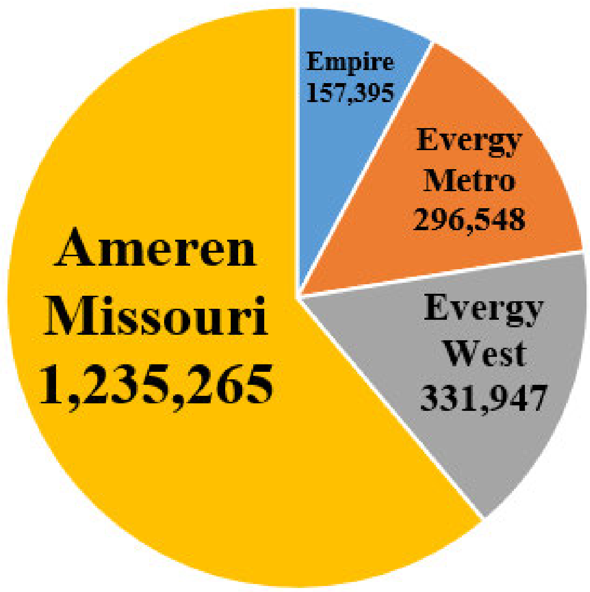
Q. What should the Commission note from these two tables?

A. There are many different inferences one can draw from these two tables, but I would like to focus on three specific elements: size, usage and costs. Figure 1 illustrates the difference in

[2] See GM-1.
[3] I have not included Commercial, Industrial and Transportation classes due to the large variation in size and tariffed rates.

utility customer size with a pie chart based on the number of all customers across Missouri IOU's.

Figure 1: Total amount of all customers per Missouri IOU



Q. Why is customer size an important variable to remember?

A. On a practical level, greater scale economies. Consider for a moment that Ameren Missouri is ten times bigger than Empire. Too often in regulatory proceedings I believe stakeholders fall victim to scale distortion in appreciating this fact. For example, a $50.1 million (or $80 million w/ Storm Uri) revenue requirement increase sounds a lot more reasonable after Ameren Missouri requested a $300 million increase. The pie chart above illustrates that this is not true as there are approximately 9 and ½ Ameren Missouri customers for every Empire customer. This is, in part, why Ameren Missouri and Empire customers consumed the same amount of energy on average per month in 2020 but Empire customers paid $31.68 more on average per month according to EIA (or $380.16 more a year).

Q. What should the Commission note about usage?

A. That all of our Missouri residential IOU's consume a lot of energy. According to the EIA:

> In 2020, the average annual electricity consumption for a U.S. residential utility customer was 10,715 kilowatthours (kWh), an average of about 893 kWh per month.[4]

Only Evergy Metro customers consume less energy than the national average; however, Evergy Metro's large average monthly bills suggest they are paying more for that energy than other customers on a per kWh basis. This can be attributed, in part, to the other three utilities having various levels of electric space heating customers. Having a lot of electric space heating customers means that affordability and rate design are crucially important elements for Commission consideration.

Q. What should the Commission note about costs?

A. That <u>all of Empire's customers are already paying more</u> on average.

Because Empire has considerably fewer customers, who are already paying above average for electricity consumption that greatly exceeds the US household average, any increase will necessarily exacerbate existing higher rates on this small customer base even more.

These observations underscore why I find Mr. Wilson's fundamental objectives and principle ("approached through the lens of the customer") misleading, at best.

Q. How is Mr. Wilson's assertion that the Company wishes to share the benefits of Empire's technology transition misleading or worse?

A. This a bold statement to make when you consider all of the items the Company is requesting the Commission to put entirely on its customers. A non-exhaustive list of items Mr. Wilson does not want shareholders to share, but does want to earn a profit on include:

- 100% of Storm Uri fuel *and* carrying costs at its weighted average cost of capital;
- 100% of its stranded meters with a return on for profit on assets no longer used and useful;

[4] U.S. EIA (2021) Frequently Asked Questions (FAQS) https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

- 100% of its 15-year prematurely retired stranded Asbury Generation unit with a return on, at its weighted average cost of capital on an asset no longer used and useful; and
- 100% of its AMI investments with a return on for profit when the only customer "benefit" includes the ability to be shut-off remotely.

As for the three wind projects and the "market protection plan" that will enable customers to share in the risks associated with playing the Southwest Power Pool (SPP) market flush with wind generation to the tune of $1.2 billion over the next ten years, I defer to the rebuttal testimony of OPC witness Lena Mantle.

Q. What about Empire's request to extend the amortization on many of these investments?

A. While amortization can lessen rate impacts in the short term, it also raises intergenerational inequities, increases profits for shareholders and ultimately increases costs for customers. It also places customers in a terrifying position in the future as Empire follows through on its billions of dollars of planned plant-in-service accounting (PISA) investment, especially if its wind projects do not cover their costs, or another Storm Uri-like scenario hits this Company and its customers.

Q. What is your response to Mr. Wilson's assertion that the wind projects' SPP wind revenues will offset the impact of their costs?

A. I've written at length on Empire's failure to update its modeling assumptions after it got the outcome it wanted. My direct testimony also cited both the Commission and the SPP market monitor on the topic. Restated here, the Commission in Ameren Missouri's 2020 Integrated Resource Plan in Case No: EO-2021-0021:

> However, the Commission shares Staff's concern (Concern C) that adding large amounts of renewable generation that are not required to meet MISO resource adequacy requirements or Missouri statutory or rule requirements, including providing safe and adequate service, may place an undue level of risk on ratepayers based on the speculation that market revenues will exceed the overall costs of the assets. Ameren Missouri inherently benefits its shareholders by investing in renewable energy while

> seeking a return on those investments through future rates. However, that same investment may shift risk to ratepayers that market revenues from the investments may not exceed the costs of the investments.[5]

And the SPP's market monitor had this to say on new generation:

> Given the relatively low average SPP market prices, the MMU [Market Monitoring Unit] does not expect SPP market prices to support new entry of generation investments. While the SPP market on its own offers low incentives for new generation, some reasons for new generation investments include expansion of corporate renewable goals, SPP market protocol requirements, federal and/or state incentives, state-regulated investments, emerging technologies, and emission reduction plans. . . . In 2020, SPP market revenues were also insufficient to support the costs of new entry of renewable generation, wind and solar. . . . As the market is currently designed, it does not incentivize new entry for energy capacity.[6]

Note that the delta in "expected revenues" in what Empire and parties agreed to in EA-2019-0010 (Table 3) and what Empire is now claiming is likely to happen (Table 4) is now more than **__________ **

[5] Case No: EO-2021-002. Order Regarding 2020 Integrated Resource Plan, p.4.
[6] SPP (2021) State of the Market 2020. https://www.spp.org/documents/65161/2020%20annual%20state%20of%20the%20market%20report.pdf

Table 3: Excerpt of Expected Case Revenues Years 1-10 within the "Market Protection Plan"[7]

Years	1	2	3	4	5	6	7	8	9	10
SPP Market Revenue	64,471,600	69,448,182	72,576,623	76,390,854	79,237,197	81,804,765	85,422,609	88,921,482	92,717,430	96,947,113
Wind Revenue Requirement	79,450,096	73,039,349	75,127,484	73,479,569	73,358,679	82,513,078	80,900,583	79,975,732	78,809,234	76,810,531
PPA Replacement Value	0	0	0	0	0	18,798,365	18,463,438	18,378,491	27,815,790	27,110,346
Annual Wind Value (AWV)	(14,978,496)	(3,591,168)	(2,550,860)	2,911,285	5,878,517	18,090,053	22,985,463	27,324,241	41,723,986	47,246,928
Accumulative AWV	(14,978,496)	(18,569,664)	(21,120,524)	(18,209,239)	(12,330,721)	5,759,331	28,744,795	56,069,036	97,793,022	145,039,951

Table 4: Excerpt from OPC DR-8075 Revised Expected Case Revenues Years 1-10 within the "Market Protection Plan"[8] **

**   To be clear, in the span of two years Empire has moved from projecting a $145 million in accumulative Annual Wind Value to **____________ **

I can also think of no compelling reason why this information is confidential to the public now, but wasn't when the Company filed its nonunanimous stipulation and agreement.

Q. What is your response to Mr. Wilson claiming that the wind projects performed well during Storm Uri?

A. They did not. OPC witness Lena Mantle's testimony goes into detail over each unit's performance as well as how Asbury would have performed had it been operating at its nameplate capacity.

[7] Case No. EA-2019-0010 Non-Unanimous Stipulation and Agreement p. 28.
[8] See GM-2.

Q. What is your response to Mr. Wilson's assertion that the Company has "made good" on the Commission guidance from the last rate case?

A. Mr. Wilson cites to three examples where the Company has "made good" on Commission guidance from the last rate case including: AMI rollout, customer service training, and improved payment options.

Regarding AMI, they have been rolled-out in the sense that the Company is ready to start earning a profit off of two separate accounts of meters now but is not prepared to offer time-of-use (TOU) rates to its customers.

As to call center training, my direct testimony included eight years' worth of data that suggests the Company has improved marginally in some areas, but has not approached its pre-acquisition (pre-2017) numbers yet.

Finally, as to improved payment options, the Company may offer a pay by text option in the future.

For my part, I remind the Commission again that Empire continues to have some of the worst JD Power customer satisfaction scores in the nation.

Q. What is your response to Mr. Wilson's assertion that the Company is responsibly managing its Storm Uri Costs?

A. The Company is seeking to recover 100% of its fuel and purchased power costs plus other Storm Uri costs in regulatory assets included in its rate base where it is to collect carrying costs at a profit moving forward for 13 years—at an annual impact to its Missouri customers of nearly $30 million.

Q. With all of that in mind, do you believe the Company filed this case through the lens of the customer?

A. No, I do not.

III. ASBURY STRANDED ASSET

Q. What are the parties' positions on Empire's recovery of its investment in its retired Asbury generating plant?

A. The Company is seeking to recover the remaining balance with a return on it as if it were in rate base, although Asbury is no longer used and useful. Company witness Frank C. Graves focuses on three areas in his testimony:

- The prudency of Empire's past capital investments in Asbury based on integrated resource plan ("IRP") filings;
- The prudency of Empire retiring Asbury based on the Company's 2019 IRP filing; and
- Arguing that disallowing Empire to recover both a return of and a profit on its investment in Asbury would unfairly punish Empire's shareholders.

Staff and MECG recommend that the Commission approve a return of but not a profit on Empire's remaining balance and to shorten the recovery amortization period from 26 years to 15 years and 13 years, Staff and MECG, respectively. Staff witness Mark L. Oligschlaeger discusses the following in this direct testimony:

- Missouri historically not allowing recovery of plant assets that are not "used and useful";
- That customers should pay for the remaining depreciation balance on Asbury despite only receiving a few years of service for those investments due to recent political, economic, and regulatory changes affecting the electric industry; and
- That shareholders not be allowed to "recover on" the remaining balance and the amortization of the regulatory asset should be fifteen years.

In his direct testimony MECG witness Greg R. Meyer takes a similar position, but also notes that:

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- He recognizes the legitimacy of arguing against allowing the Company to recover the remaining undepreciated balance due to only receiving 25% of its expected life, but is not opposing that recovery;
- That shareholders should not be allowed to "recover on" the remaining balance and decrease the amortization of the regulatory asset to thirteen years; and
- That securitization would be an optimal path forward for everyone, but that the Company alone would have to initiate that.

I respond to each of these parties in turn.

Q. Would you remind the Commission of your recommendation for Empire's stranded investment in Asbury?

A. Empire should not continue to profit on—receive "a return on"—its investment in Asbury after Empire retired Asbury on December 12, 2019, and Empire should not receive "a return of" the remaining balance of its 2015 air quality control system ("AQCS") investments of $124 million in Asbury that extended the useful life of the plant to 2035.

Q. Does that mean you are recommending that Empire gets no recovery of its stranded investment in Asbury?

A. No. I am recommending that the Commission allow Empire's shareholders to get 38% of Empire's undepreciated investment balance in Asbury. My recommendation regarding no "return on" is consistent with the Staff and MECG. I differ from those two parties as it pertains to the remaining balance of the 2015 Air Quality Control System investment that only operated for five of the twenty years it was supposed to.

Response to Empire

Q. What is your response to Mr. Graves's testimony on Empire's historical IRP modeling results?

A. Mr. Graves makes a compelling argument that Empire has not modeled its resource planning very well to date, but little to support his argument that shareholders should continue to earn a profit on an asset that Empire chose to strand. Empire's preferred plan selection within those various modeled scenarios from previous IRPs have not resulted in optimal outcomes for ratepayers to date. Empire's high cost of service and poor customer satisfaction scores are testaments to that. More to the point, regulatory approval at the time of investment does not form a basis for full cost recovery in light of management actions that resulted in Empire choosing to strand (in Empire's words) "a perfectly usable mid-life coal plant."[9]

The regulatory system leaves entrepreneurial decisions and capital management in the hands of utility management, not regulators. I believe Empire's decision to invest in the ACQS and lock the Asbury unit into a path-dependent trajectory for the next twenty years was supported at the time by management's decision to both be more efficient and environmentally sound. Retrofitting Asbury and extending its useful life for twenty-five years was a management choice to not deviate from having a diverse portfolio of resources as a hedge against uncertainty (like erratic weather) for a comparatively small utility.

It was Empire's management who took the risk of doubling-down on its historic coal-investment by retrofitting Asbury into one of the most efficient and environmentally sound coal plants in the country, and if was Asbury were still operational, I would not be arguing for a partial disallowance of that investment.

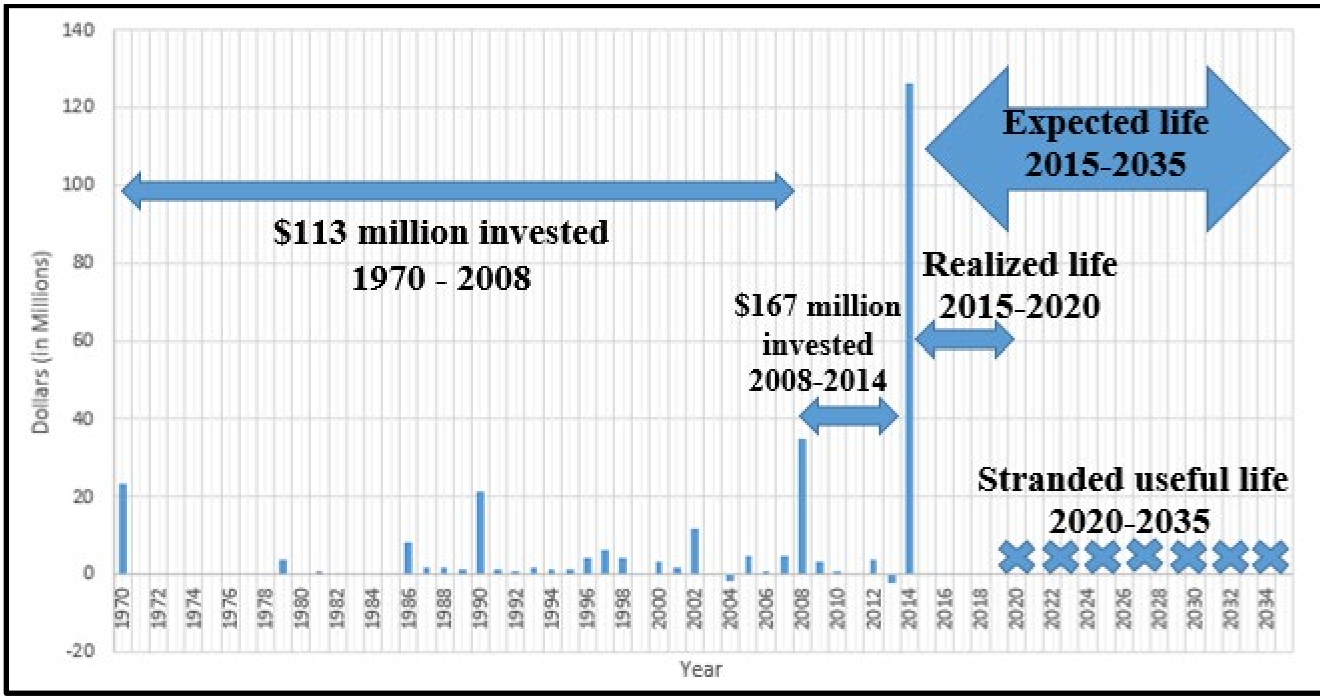
It was also Empire's management (albeit a different set of managers) who assumed the risk by stranding an efficient baseload asset with fifteen years remaining life so that it could utilize Asbury's SPP interconnection lines for its intermittent North Fork Ridge Wind Farm. Empire's management is also taking the risk that it will be allowed to recover its remaining balance and earn a return on its investment in an asset that is no longer used and useful.

Empire's AQCS investment in Asbury is not a trivial amount, to place Empire's investments in Asbury in perspective, consider that Empire invested a total of $113 million in Asbury from when it built Asbury (1970) to 2008. Now consider that in the years 2008 through

[9] Case No. ER-2021-0312. Direct Testimony of Geoff Marke, GM-3 p. 15.

2015 Empire more than doubled that capital investment by retrofitting Asbury with an additional $167 million in environmental and efficiency investments that extended its operational life through 2035. Figure 2 shows the dollars (in millions) invested over the course of Asbury's life with an emphasis placed on expected vs actual operation life from the ACQS investment.

Figure 2: Asbury Plant year-over-year capital investments in millions of dollars[10]



To be clear, I am not arguing that all of Asbury's stranded investment be written down. I am arguing that just the remaining undepreciated balance on the ACQS (approximately 62% of total) should be borne by shareholders, and that Company should no longer earn a profit off of its investment in the nonexistent power plant that is no longer used and useful.

[10] Data for this graph was sourced from the 2016 depreciation study submitted to the Commission in Case No. ER-2016-0023.

Q. What is your response to Mr. Graves's testimony on Empire's 2019 IRP to justify the prudency of Empire stranding its investment in Asbury?

A. Mr. Graves omits two very important Company actions that influenced its 2019 IRP preferred plan outcome.

1.) The Company's decision to gamble in the SPP market with its wind project—three wind farms—funded by ratepayer-backed capital that exceeds $1 billion in total; and that

2.) Asbury was an extremely efficient unit; it only became less efficient as Liberty decided efficiency no longer mattered when trying to maximize profits from the unit in the SPP market, which directly impacted the unit's average capacity factor.

To be clear, when Mr. Graves speaks of "benefits" to customers based on the 2019 IRP modeling (*i.e.*, retiring Asbury), he is talking about a modeled outcome based on certain assumptions that were highly contested. Importantly, these models and assumptions were not accurate then, and have proven to be wholly inaccurate since.

Q. Can a utility select a preferred plan using an IRP where the assumptions underlying that plan are wrong?

A. Sure. Empire has done this consistently. Empire's high cost of service and poor customer satisfaction scores are testaments to that.

Q. What if parties don't agree with a utility's IRP?

A. There is no real recourse in the IRP process. Stakeholders can voice their concerns and file recommendations, but the prudency of management's decisions are based on management's actions. IRPs are a modeling exercise that is constantly evolving. Any deficiencies or concerns voiced are historically corrected in the next filing. For example, carbon pricing has yet to occur for any of our utilities, but they continue to model scenarios with various cost assumptions (depending on the utility in question) as if various types of carbon pricing will happen. The end result is a complete overstatement of "benefits" on this one metric alone.

Q. Does that mean IRP serves no purpose?

A. I don't believe so, but more importantly <u>the IRP process is not Missouri's bright line test for prudent investments</u> nor has anyone seriously argued that it should be until now. In fact, treating IRP as such would enable utilities to game the regulatory process more than they already can. Consider that utilities routinely change direction in preferred plans, and the only recourse for stakeholders is to document historical grievances and wait until their next IRP filing.

Q. Did OPC raise concerns about Empire's modeling assumptions for its wind projects and Empire's analysis of the economic viability of Asbury before Empire retired Asbury?

A. Yes, this was made clear in Case No. EA-2019-0010. Empire delayed its triennial filing until the Commission had opined on a CCN for the wind projects in that case, apparently in part, to avoid OPC's objections that it needed to update its modeling assumptions regarding its Customer Savings Plan. Unsurprisingly to me, Empire filed its new IRP nine days after the Commission issued its report and order in Case No. EA-2019-0010, creating a scenario where Asbury generation would actively hurt Empire ratepayers. Because ratepayers now were in the precarious position of being merchant generation investors (without the monetary reward) in three soon-to-be-built wind farms.

I strongly recommend that the Commission refrain from buying into this rhetorical argument. Commission affirmation that the IRP process serves as the bright line for prudency will result in an absurd outcome which utilities will exploit to no end as they effectively have absolute control over the IRP process.

Regulators and consumer advocates have neither the resources, nor responsibility, to create and guarantee utility investment plans, and cannot be expected to match the deep supply of outside consultants and resources available to utilities. That is why utility management is compensated as well as it is—to manage.

Q. What about Asbury's diminished capacity factor?

A. Simply put, Asbury was an extremely efficient unit until the Company decided that it wouldn't be by changing how it operated. The 2019 IRP's "benefit's" created from stranding Asbury came as a result of the Company's decision to have the unit run differently than for how it was designed to run. No modeling was done to consider seasonal dispatch, mothballing, or selling the unit. OPC witness John Robinett addresses the issue of efficiency and managerial actions in greater detail in his rebuttal testimony.

Q. What is your response to Mr. Graves's argument that disallowing any return of or profit on Empire's stranded investment in Asbury would unfairly punish investors?

A. When Algonquin (Algonquin Power and Utilities Corp) first acquired Empire they effectively found themselves in a situation of lemons. That is, Empire was long on capacity with new capital investments made to secure the Company for the next twenty-five years. The new management then somehow managed to make lemonade out of its lemons by getting approval to have ratepayers back 600MW of wind farms in areas with poor wind profiles to the tune of over a billion dollars. The Company accomplished this feat, in part, through very untraditional schemes to finance a categorically large increase to rate base when no such investment was needed. This whole scenario, retiring Asbury, tax equity financing, etc… was assessed prior to Algonquin's acquisition of Empire and exercised many years before it was recommended by their outside evaluator, and now investors are seeing a windfall of rewards. Investors are also in a position for even further capital investment moving forward because of this management-created scenario to reduce the risk of investors by continuing to expose its already burdened customers with market volatility. I would say investors are doing extremely well even if the Commission were to fully disallow the remaining undepreciated balance of Asbury, a result that is above and beyond my recommendation.

Q. Do you have any concluding statements to make on this topic?

A. As glowing of a scenario as it is for investors, Empire's customers are not reaping the benefits of Empire's managerial decisions. Consider for a moment an excerpt from my direct testimony in the first Empire wind project case, Case No. EO-2018-0092:

> Make no mistake of it, what Empire is requesting here is unprecedented. The Commission would be well advised to keep in mind the urgency (or scarcity) principle and have a healthy degree of skepticism when it comes to regulatory requests that apply an "act now, limited time only pressured sales pitch."[11] Because of past managerial decisions, Empire cannot afford to shift risk onto its ratepayers by locking them into a scenario where they would increasingly be exposed to the uncertainty of excessive costs on the SPP market with an excessive amount of generation capacity.
>
> The decision in front of the Commission is not to build a coal [plant] *or* wind farm. The coal plant is built. Nor does OPC believe this is merely a decision to retire Asbury and replace it with wind. Instead, what is at stake is a complete departure from how Empire has operated to date—namely, to provide safe and adequate service to meet its native load. Figures 1-3 provides a breakdown of the stated and unstated investment and operational decisions for the Commission's consideration.

[11] See also Cialdini, R.B. (2006) *Influence: The Psychology of Persuasion*. Harvard Business.

Figure 1: Graphical illustration of Asbury generation to serve load (current state)

Figure 2: Graphical illustration of Company's proposed application

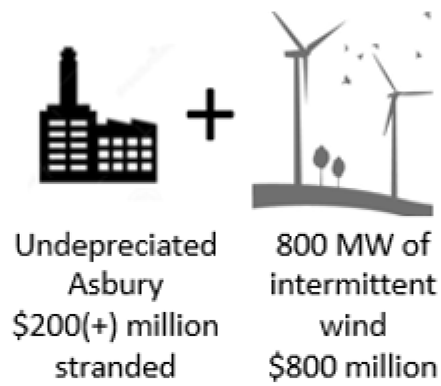


Figure 3: Graphical illustration of OPC's interpretation of Company's proposed application

The ratepayer "benefits" hoped to be obtained in this transaction are based on projecting assumptions far out into the future based on narrowly defined parameters. In contrast, the "benefits" to shareholders are guaranteed, at least in the short-term.

> OPC's greatest fear in this proposal is locking-in Empire's largely rural southwest Missouri ratepayers into volatile, excessive rates into the future.

It is now 3 years and 10 months since I wrote this, and sixteen months before Empire filed its 2019 IRP, and I contend that my offered outcome has proven more accurate than Empire's 2019 preferred plan. We are now realizing Figure 3's outcome, only at slightly smaller scale and albeit with a different season (winter) of volatile market prices.

While it "may" seem unfair to Mr. Graves to only partially disallow some of Empire's undepreciated balance of Empire's stranded investment in Asbury, it is profoundly unfair for Empire's shareholders to recover from its customers for excessive and "gamed" utility investments. Nobody persuaded Empire to make any of these investments. Anyone arguing that automatic full recovery is entitled to shareholders because of utility-backed and approved IRP model's based on the Company's own assumptions are over-relying on regulation to get the Company out of the compromising situation it alone created.

Response to Staff

Q. What is your response to Mr. Oligschlaeger's recommendation to allow Empire to recover the remaining undepreciated balance *of* Asbury but not a return *on* that stranded asset?

A. It is profoundly unfair to ratepayers, and sets a very bad precedent moving forward.

Q. What is your response to the argument that utilities will not retire coal plants in the future if the Commission does not allow Empire to recovery all of its stranded investment in Asbury?

A. This is nonsense. The recently passed Securitization law in Missouri is extremely utility-friendly and nullifies that argument. The fact that Empire received categorically better treatment from the Commission with the approval of its wind farms effectively as "replacements" for Asbury underscores this argument. I address this further in my response to Mr. Meyer. When units need to be retired and are no longer producing appropriate benefits for customers and shareholders, I am confident stakeholders and utilities will argue accordingly. The fact that I am only asking for partial disallowance further negates this line of thinking.

Q. What is your response to Mr. Oligschlaeger's argument that political, economic and regulatory changes support Staff's recommendation to only disallow return on Empire's stranded investment in Asbury?

A. I am not sure what he is referring to. To date, there has been no carbon pricing, no increase in Missouri's statutory Renewable Energy Standard and the last four years have seen an unprecedented increase in intermittent generation and decrease in base load generation in SPP making the economics of small environmentally compliant and efficient baseload plant more, not less attractive.

I will counter this general blanket observation with another—that cost prohibitive rates, a 30-year high in inflation, a worldwide pandemic, a historic winter freeze for which utilities, including Empire, incurred hundreds of millions of dollars in fuel for a week of utility service, and a windfall increase in rate base above and beyond the existing Asbury unit for some of the more financially challenged ratepayers in the state supports my recommendation for partial disallowance of Asbury, specifically, the remaining undepreciated balance of the AQCS investment that extended the useful life of the plant twenty-years.

Response to MECG

Q. What is your response to MECG's argument that Asbury could be securitized?

A. It may be an option, but only if Empire elects to pursue it. Empire has not done so, nor has it indicated that it plans to do so.

Moreover, consider what would have happened if Empire had not moved forward with the 600MW of wind or prematurely retired Asbury until after securitization was available to it. In this hypothetical, Empire could file and get approval to securitize the remaining undepreciated balance of Asbury, then make a dollar-for-dollar capital investment, say a wind farm in Missouri. In this scenario, Empire could be allowed build nearly $200 million worth of non-capacity equivalent wind generation and continue to earn a return on this wind investment for its thirty-year life.

Now consider~~,~~ what actually happened. Empire and its tax equity partners invested over a billion dollars in three wind farms, with Empire including half of that investment in its rate base with plans to include the other half in ten years, with ratepayers effectively covering any poor wind performance by those wind farms.

Where securitization case could have left investors whole dollar-for-dollar in investments, because of what it actually did Empire is arguing for five dollars (1/2 the cost of the wind investments now) *and* every dollar of its stranded investment in Asbury. Further, investors get to include the undepreciated investment in the wind farms in Empire's rates after buying off the tax equity partner, anticipated to be in ten years *and* while future investment opportunities abound, but leave customers exposed to SPP market volatility now and in the future.

My illustrations above highlight how one-sided this process is for the Company's benefit, and how unfair it is to Empire's customers. Disallowing a portion of the remaining undepreciated balance of Asbury begins to rectify that distorted outcome.

Q. Do you have any final comments on this topic?

A. The Commission could choose to shift all risk to ratepayers, guaranteeing Empire with full recovery of all of its investment in its wind projects and in Asbury, and ensuring Empire realization of authorized returns on everything Empire wants (the billions in wind investments and the remaining $200 million on Asbury). But understand that this would negate the value of a structural model centered on private investment, and wouldn't change the fact that Empire's customers are more exposed to SPP market volatility today than when Asbury was an available generating resource. The state granting to a monopoly of exclusive franchises with captive customers has strings attached—economic regulation—to ensure safe and reliable service at just, reasonable and affordable rates, and it is incumbent on the Commission to say investors are getting enough and that Empire's ratepayers are paying enough. I continue to recommend the Commission order a disallowance on the remaining undepreciated balance *of* the AQCS and reject an Empire profit *on* the balance of stranded Asbury investment remaining thereafter.

IV. TRANSMISSION AND DISTRIBUTION INVESTMENTS

AMI

Q What benefits will Empire's customers receive from Advanced Metering Infrastructure ("AMI" or "smart meters")?

A. According to the Company's website's "Smart Meter Features & Benefits" section the following benefits are listed:

- Meter readings will be automated. This means few to no estimated bills.
- Automated meter readings provide cost savings with fewer service calls and service trucks on the road. This also reduces vehicle emissions, protecting the environment.
- Starting or stopping service will be done more quickly and efficiently.
- Customers can better track and manage usage throughout the month with near real-time usage data provided through a simple, user-friendly website portal.
- Smart meter information helps our service teams troubleshoot and resolve problems with equipment or services and provides timely outage and safety alerts. This helps customers by reducing the need for them to call to report issues or outages.
- Smart meters help to modernize the energy grid and our distribution systems. This helps to improve reliability and service restoration when an outage or issue occurs.

- Smart meters also help our utilities plan for the future by providing precise analysis to help us design pricing plans and service options that match customer needs and energy and water use.[12]

Q What is Empire proposing for its AMI investment?

A. In direct testimony, Empire witness Chad C. Hook devotes ten pages to restating (and restating) the aforementioned points as evidence that Empire's recovery of its $43.4 million investment (so far) in smart meters in this case is prudent. What is missing from the Company's website or Mr. Hook's testimony is any attempt to quantify the benefits against the large cost increase to switch to AMI and the Company's stranded undepreciated meters.

Q. Do you believe these benefits outweigh the costs?

A. Absolutely not without TOU rates and even then I would want some monetary quantification of the espoused savings from the timely outage alerts or estimated bills (a practice that should not be dependent on $43.4 million in capital investments to rectify) that the Company highlights as tangible benefits.

Admittedly, Empire has struggled with billing and customer satisfaction, but as it stands now, the real beneficiary are shareholders who get a sizable increase to the Company's rate base by adding new hardware and software on top of the existing undepreciated meter balance. An additional $43.3 million in capital investments is a large expenditure to rectify Empire's billing problems (a product of their own creation) and will likely have a negative impact on customer satisfaction as favorable perception appears to be closely tied with affordability—which will only be exacerbated by this expense.

Q. What is your view of Empire's AMI investment?

A. If Missouri was a pre-approval state in which a utility would need Commission approval to move forward, I seriously doubt it would be approved under the current roll-out and circumstances. A consistent theme throughout Mr. Hook's testimony is that "everybody

[12] Liberty (2021) Smart Meters Features and Benefits: Improving Your Customer Experience https://libertyutilities.com/smartmeters/features-benefits.html

else is doing it" which somehow justifies Empire's decision. As I pointed out approximately two years ago in Empire's last rate case, state commissions in Virginia, New Mexico, Massachusetts and Kentucky all rejected utility AMI proposals because the customer benefits did not outweigh the costs to customers. I then stated:

> My fear is that Empire will stagger deployment of these three parts to increase its rate base without having to realize benefits to its customers. Such a scenario could play out as follows: Empire completes part 1 (AMI hardware) in time for the test year in the next rate case. Part 2 (CIS interface); however, is not completed for another two years (or more). Part 3 is realized over the next 10 years in staggered opt-in pilot pricing programs. That scenario is a slow bleed deployment that rewards the utility with profits without having to produce benefits (at least immediately) for customers.[13]

As it stands, my fears are being realized. Part 1 has happened. I am frankly unsure about part 2, as I cannot state conclusively whether Empire has additional AMI software investments to make to support TOU rates. And part 3 is being realized through the Company's request to limit its TOU offering to only 500 residential customers (less than ½ a percent of the residential customer population).[14]

I repeated these concerns after the Company submitted its PISA plan earlier this year in Case No. EO-0219-0046 stating, in part:

> Titling an initiative "Customer First" does not make it so. Based on the staggered deployment of metering infrastructure (hardware first, software years later) and emphasis on increasing rate base (no reference of customer education plans) it is clear that the initiative should be renamed "Shareholder First." This is because shareholders will be earning a sizable return on their investment years before customers stand to

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[13] Case No. ER-2019-0374 Direct Testimony of Geoff Marke p. 45, 7-13.

[14] I would note that in its 2021 PISA filing (Case No. EO-2019-0046) the Company projected a $132.4M in future "Customer First" costs to be made over the next few years which include many AMI elements (collection of usage, billing, etc…).

gain any benefit from AMI investment in the form of Time-of-Use ("TOU") rates. The staggered nature of the AMI investment ensures that shareholders will be profiting while ratepayers' benefits are delayed indefinitely.[15]

Q. What is your recommendation to the Commission as it pertains to Empire's AMI investment?

A. My recommendation remains that the Company should not earn a return on any of its AMI capital investments until all of its customers can at least have the opportunity to utilize TOU rates to attempt to control their high bills. The Company needs to demonstrate that it is not merely gold plating its distribution system for the benefit of shareholders. It's been approximately two years since I wrote about this in the Company's last rate case, my testimony should not be a surprise to them. Unfortunately, the Company's lack of cost benefit data and reliance on aspirational benefits is not a surprise to me either. Empire seems singularly focused on increasing rate base at the expense of sacrificing affordability for its customers. I challenge Empire to prove me wrong in surrebuttal by demonstrating that the AMI capital investments benefits exceed the costs and that the assets in place are not being used as promised.

Disallowing a "return on" but not a "return of" the costs of the AMI investments prevents shareholders from receiving benefits (profits) until ratepayers can as well (control over their bills). Equally as important, it would send a clear message the Company has to start considering the rate impacts its managerial decisions will have on its captive customers.

[15] Case No. EO-2019-0046 Memorandum: Response to the Empire District Electric Company d/b/a Liberty PISA Report and Presentation on March 25, 2021. Submitted on April 6, 2021.

Undepreciated Meters

Q. What is your response to Empire's attempt to recover the remaining undepreciated balance and continue to earn a return on its stranded meters following its AMI roll-out?

A. I would say it is yet another example of the Company putting shareholders before ratepayers. Consistent with my recommendation above regarding the AMI meters, I recommend the Commission disallow a "return on" but not a "return of" the $9,010,642 of the stranded meter investments the Company is requesting to keep in a regulatory asset to be included in rate base.

Q. Ms. Sanderson cites to the Commission order approving the Stipulation and Agreement in ER-2014-0370 as an example of how these costs have been treated in Missouri. What is your response?

A. The various settlement agreements entered into and approved by the Commission did not explicitly opine on the ratemaking treatment of the stranded meters.

Q. Are you aware of any commissions that have disallowed a return on the undepreciated investment in retired meters?

A. Yes. The Kansas Corporation Commission disallowed a return on the unrecovered treatment of approximately $11 million in stranded meters. The KCC stated:

> While the Commission accepts the decision to retire the AMR meters as prudent, it does not follow that KCP&L is entitled to a return on its investments when the investments is no longer "used and required to be used," KCP&L is not entitled to a return *on* its investment. As a prudent business decision, KCPL&L will receive a return *of* its investment, but a return *on* its investment. . . . Accordingly, the Commission believes allowing KCP&L to amortize the retirement of its AMR meters over a ten-year period strikes a fair and reasonable balance between the

> investment expectations of KCP&L's shareholders and the cost concerns of KCP&L's customers.[16]

Based on this strong language from the KCC I am fairly confident that Empire's Kansas customers will not have to pay a return on an investment that is no longer used or required to be used.

Project Guardian

Q. What is Project Guardian?

A. Based on Mr. Hook's testimony it appears as though it is a series of capital investments devoted to increased physical security of substations in Empire's territory. Project Guardian is expected to be completed by 2025 and appears to encompass up to 180 sites. As it pertains to this case, Project Guardian is being presented as a "pilot" in which approximately $1 million was spent physically securing one substation and one security monitoring center in the Company's existing contact call center radio room in Joplin, Missouri.

Q. What did Empire purchase to physically secure the substation?

A. It is not entirely clear to me. Mr. Hook lists the following items as having been investigated at the substation:

- Security cameras
- Radar scanners
- Deterrent lighting
- Thermal sensors
- Servers
- Video management
- Analytical software

[16] See Order on KCP&L's Application for Rate Change, Docket No. 15-KCPE-116-RTS, issued September 10, 2015, at page 22.

In addition to these items he states that wall mounted monitoring screens and workstations were added at the new security monitoring center in the Company's existing call center.

Q. How have utilities historically protected substations?

A. Chain-linked fencing, possibly barbed wire, as well as cautionary signage.

Q. Has Empire faced a series of substation threats?

A. Not to my knowledge.

Q. Generally, are you aware of any substation attacks?

A. The one I am most familiar with is the Metcalf sniper attack on PG&E's substation near San Jose, California in 2013. The attack, in which gunmen fired on 17 electrical transformers, resulted in more than $15 million worth of equipment damage, but it had little impact on the station's electrical power supply.[17]

I am also aware that an unknown gunman knocked out an electric substation in rural south-central Utah in 2016.[18]

Q. Would any of the items Mr. Hook lists prevent a planned sniper attack?

A. I don't know. I suspect if someone is motivated enough to take down a substation I suspect no amount of precautions will suffice. That being said, I'm not sure how the aforementioned deterrents would prevent sniper fire.

Q. Are you advocating for further capital investments that would?

A. I am not.

Q. Does the North American Electric Reliability Corporation (NERC) have standards for security on critical substations?

A. Yes. I am aware of CIP-014 standard as it pertains to transmission substations but I'm not sure if the Joplin substation would qualify under that standard, if the selected retrofits are in

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[17] More details of the attack, including surveillance video of the attack can be seen at Wikipedia (2021) Metcalf sniper attack https://en.wikipedia.org/wiki/Metcalf_sniper_attack

[18] Behr, P. (2016) Substation attack is new evidence of grid vulnerability. *E&E News*. https://www.eenews net/articles/substation-attack-is-new-evidence-of-grid-vulnerability/

compliance with that standard, or if there is a more updated NERC physical security substation standard in place as the standards tend to allow for a fair amount of utility discretion in that no single standard is a panacea for all.[19]

Q. Did the Company provide the results of the approximately $1 million it has already spent on this "pilot" project?

A. No. Nor am I entirely sure what the learning objectives were or how this project would even qualify as a "pilot."

Q. Do you believe the approximate $1 million in security upgrades were a prudent investment?

A. I don't know. At face value, $1 million is an awful lot of money for increased security of effectively one substation. Admittedly, I came across this issue late in my review of this case, which has prevented me from issuing discovery or receiving responses back in a timely manner, but I have many questions about this project and the future of Project Guardian that I will attempt to revisit in surrebuttal testimony after said discovery is issued.

Q. What is your recommendation?

A. Without further context, at the moment, I recommend the Company meet with Staff and OPC on this and all other "pilots" it is currently running or plans to run. I cannot definitively state whether this was a prudent investment at this point, but consider this testimony as at least putting the Company on notice that this is a concern and allow them the opportunity to respond accordingly in surrebuttal.

A million dollars is a lot to spend on various levels of security cameras and associated media to (possibly?) physically secure a single substation. Regulatory approval of this project without proper oversight could set a costly precedent (this was a pilot for one site; 180 sites were identified). Perhaps we need to retrofit the existing substations with costly cameras, sensors and scanners, but a cost-benefit justification that these expenditures were necessary

[19] See CIP-014-1 Physical Security at https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-1.pdf

and lays out that rationale empirically would go a long way in convincing me that this and future Project Guardian spend are a prudent use of captive ratepayer money.

PISA

Q. Do you maintain the same level of concern for other possible PISA-related investments moving forward?

A. I do. Earlier in testimony I referenced the memorandum that OPC filed in Empire's PISA case, EO-2019-0046, before Empire filed its direct testimony in this case. Under the section titled Part III: Safety & Reliability I wrote:

> Part III of the PISA/Customer Transition focuses on capital investment in infrastructure to:
>
> *Ensure the infrastructure continues to operate safely and reliably.*
>
> It includes the following cost categories:

• Distribution Automation	\$78.9M
• T&D Resiliency	\$225.7M (Transmission) + \$480.7M (Distribution)
• Substation S&R	\$96.2M
• Plant Optimization	\$108.5M
Total	\$990M

> Seemingly operating under the assumption that the more zeros found in the price tag, the less scrutiny it will receive, Liberty puts forward just under a \$1 billion in planned safety and reliability investments over the next five years in 3 ½ pages of its 20-page report. Based on the available information provided, high level concerns include:
>
> - \$990M in planned safety and reliability investment void of any meaningful details
> - The lack of any cost-benefit studies or references to such an analysis;
> - Undergrounding any part of the distribution or transmission system;
> - The cost-effectiveness and rationale behind "sustainable microgrids";

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- What problems Liberty is solving, and how the benefits will outweigh the cost and accompanying customer bill increases; and
- Further capital investments in existing fossil fuel generation ("Generation Optimization") given this Company's track record of continuing to expect a return on and of the capital expenditures made to increase efficiency and extend the useful life of the Asbury Power Plant only to strand it shortly thereafter.[20]

Empire did not respond to OPC's comments in the PISA docket.

Q. Did any other witness speak to distribution and transmission investments outside of the two examples you cited above?

A. Yes. Empire witness Jeffrey Westfall filed testimony on transmission and distribution investment the Company is seeking to recover in this rate case.

Q. Did Mr. Westfall's testimony reference the words PISA or "plant-in-service accounting"?

A. No. Mr. Westfall provides testimony on "Operation Toughen-Up" that accounts for approximately $23 million in costs and then references additional T&D investments that include Operation Toughen Up projects that total $218,484,473 in costs.

Q. How does that total compare to the Company's filed PISA plan?

A. It's not entirely clear. Empire identified 13 separate categories in its PISA filing for a 2021 total of $338,500,000, but these categories are void of detail. Over the next four years, in the specific categories of "Grid Resiliency" Distribution and Transmission the Company has put forward an additional $475,700,000 in planned investment.

[20] Case No. EO-2019-0046 Memorandum: Response to the Empire District Electric Company d/b/a Liberty PISA Report and Presentation on March 25, 2021. Submitted on April 6, 2021.

Q. Have you seen any cost-benefit analysis to justify any of these expenditures or metrics against which Empire is benchmarking its performance?

A. No.

Q. What have you seen?

A. Only the 20-page report void of any meaningful details that it filed in its PISA docket, where it stated that it plans to spend over $2 billion from 2021-2025.

Q. Does this concern you?

A. I am very concerned for Empire's ratepayers. These planned costs need to be considered on top of the Storm Uri costs the Company is asking the Commission to treat as rate base and recover fully with carrying costs, the Asbury stranded asset the Company is seeking to continue to recover the return of and on despite no longer being used and useful, the billion dollar wind investments in which ratepayers overwhelmingly shoulder the risks of, the lack of reliable generation if customers face another winter Storm Uri scenario, and the fact that the Company already has some of the highest rates in Missouri for any utility before these costs are taken into account.[21]

Q. What do you recommend?

A. I recommend the Commission order Empire to conform to the same (or very similar) standards that stakeholders agreed with Ameren Missouri in its most recent case as it pertains to future PISA investments. In Case No. ER-2021-0240 a unanimous stipulation and agreement was entered into by parties that contained the following term:

> The Company shall meet at least three times with OPC, Staff, and other interested Signatories starting in the first quarter of 2022, and will in good faith consider meeting on additional occasions, to discuss the Company's energy delivery system projects, project justifications, and process for determining such projects. The Company agrees to consider the other interested Signatories' input on such issues. The Company shall provide updates made to its evaluation methodologies between each meeting.

[21] Not to be forgotten are Empire's customer economic demographics, a roughly 30-year high in inflation and the ongoing pandemic as referenced in my direct testimony.

The Company shall develop evaluation methodologies for major categories of energy delivery investments to be employed prior to investments in such categories (the categories outlined in Mark Birk's rebuttal testimony) no later than the 3rd quarter of 2022. Each evaluation methodology shall identify all costs and benefits that can be quantitatively evaluated and shall further identify how those costs and benefits are quantified for each category. For any cost or benefit that Company believes cannot be quantitatively evaluated, the Company shall state the reasons the cost or benefit cannot be quantitatively evaluated, and how the Company addresses such costs and benefits when reviewing and deciding on what projects to pursue. No evaluation methodology for a major category of energy delivery investment shall rely solely on costs and benefits that the Company believes cannot be quantitatively evaluated. Any quantification for a category that does not produce quantified benefits exceeding the costs will be accompanied by additional justification following the methodology(ies) adopted under this paragraph for addressing costs and benefits not quantitatively evaluated in support of the projects in each category.

The Signatories agree that different categories or projects within a category may have different methods and analysis of evaluation, and nothing in this paragraph shall be construed to suggest that all categories or projects can be evaluated under the same analysis or methodology.

B. By the end of the first quarter in 2022, the Company will submit in File No. EO-2019-0044, for those energy delivery projects falling within the above-referenced categories with an investment of $1 million or greater and which went into service the prior year (i.e., for the 2022 submission projects that went into service in 2021), the following information (as applicable, since not all the following items apply to all such projects):

a. Purchase orders;
b. Change orders;
c. Final project cost summaries;
d. Project Notifications/Project Charters;
e. Oversight Committee review materials; and
f. In-service dates.

Starting by June 30, 2022, the items listed above shall be submitted in the referenced docket for those energy delivery projects falling within the above-referenced categories with an investment of $1 million or greater and which went into service for the prior quarter (i.e., the June 30, 2022 submission will be for projects that went into service in the first quarter of 2022), and shall continue such submissions on a quarterly basis thereafter for subsequent quarters until submissions under subparagraph C commence.

> C. Starting at the end of the first full quarter after the Company finalizes the evaluation methodologies under subparagraph A, and by the end of each year thereafter so long as the Company continues to utilize Plant-in-Service-Accounting, for energy delivery projects with an investment of $1 million or greater which went into service the prior quarter for projects initiated 90 days or more after the methodologies developed under subparagraph A have been finalized, Ameren Missouri will submit in File No. EO-2019-0044 items a-f as listed in subparagraph B, and will submit the evaluation results consistent with those methodologies for the categories in which those projects were completed.
>
> With regard to outcome-based, objective metrics, they should include both baselines and targets (the values assumed when any associated benefit-cost analyses were developed).
>
> To the extent comparable information on similar projects or categories of projects by other utilities is reasonably available, such information might be used to identify and quantify criteria.[22]

I defer to Staff whether or not a Cost Measurement Savings Report as articulated in section J of the Ameren Missouri unanimous stipulation and agreement is applicable to Empire or not.

Voltage Optimization

Q. Are there any omissions from Empire's planned PISA investments that you believe the Company should investigate?

A. Yes. Mr. Westfall's testimony contains a number of historic and planned transmission and distribution investments, but neither his testimony nor the Company's filed PISA report reference a voltage optimization plan.

Q. What is Voltage Optimization?

A. Some utilities overpower homes and businesses with more voltage than is needed. This is a symptom of inefficiencies in the electric system that can negatively impact people's

[22] Ameren Missouri, Case No. ER-2021-0240 Unanimous Stipulation and Agreement pp. 7-9.

wallets, health, and the environment. If voltage were "right-sized," customers would only get the power they need to sufficiently power their appliances and devices, while building a cleaner, more efficient electricity system in the process. Voltage optimization is an electrical energy saving technique to support efficient distribution investments. Based on my understanding of distribution grid investments with other utilities, a voltage optimization plan represents "low hanging fruit" for utilities with cost-effective benefits for ratepayers.

Q. What do you recommend?

A. I recommend that the Commission order Empire to issue a request for proposal that will engage an independent third-party consultant to conduct a study of its distribution system designed to gauge the costs and benefits of a voltage optimization program in Empire's service territory. The consultant should be determined from the candidates based on ranked majority voting from the Company, Staff and OPC. The study should be conducted in calendar year 2022 with the results filed in the Company's PISA docket with a target date on or before December 31, 2022.[23]

Employee Retention/Satisfaction

Q. Are there any final comments you would like to make regarding Mr. Westfall's testimony?

A. Yes. Mr. Westfall includes a section titled, "Lineman Retention Program" effectively notifying the Commission that the previous approved program was successful in its outcome and the Company is terminating it moving forward.

[23] GM-3 includes a copy of the Ameren Illinois Voltage Optimization plan for reference. GM-4 includes a copy of the Illinois Commerce Commission Order approving Ameren Illinois's voltage optimization plan.

Q. What was the lineman retention program?

A. A 2019 program approved in the last rate case that increased pay for Company linemen after 16 left for better paying positions. After the implementation Empire has only lost two linemen.

Q. Has Empire had a difficult time retaining talent in other positions?

A. Based on my interaction with the Company there has seemingly been considerable turnover year-to-year on the regulatory side. I realize that is a small sample size so I requested the Company's Employee Satisfaction Survey's for the past five years in the hope of confirming whether this is a concern.

Q. What did you find?

A. It's a concern.

Before I go into the details, I want to note that the Company has labeled the following information as Confidential and I will treat it as such, but I struggle with why this information should have that designation.

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[24] See GM-5 for the 2021 Empire Employee Satisfaction Survey p.4

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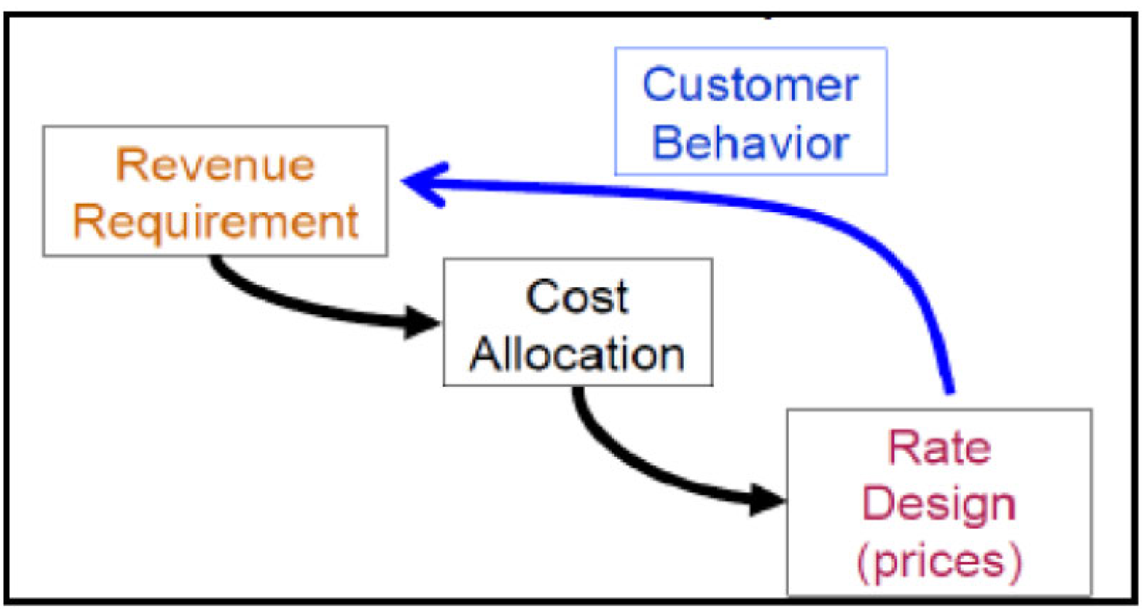
V. CLASS COST OF SERVICE

Q. What is a CCOS?

A. It is an analysis that allocates a utility's allowed costs to provide service among its various customer classes. The total cost allocated to a given class represents the costs that class would pay to produce an equal rate of return to other classes. There is no one definitive accepted method. Instead, there are different methods (e.g., Average and Peak, Average and Excess, Base-Intermediate-Peak, Capacity-Assigned, etc.) and cost allocation factors that produce different outcomes. If step one in a rate case is determining the revenue requirement, then step two is allocating those costs among customer classes. Step three then focuses on designing the rates for appropriate cost recovery. How rates are designed influences future revenue requirements, thus providing a feedback loop on the entire process. Figure 3 provides a simplified, illustrative feedback loop of the rate case process.

<u>Figure 3: The Rate Case Feedback Loop</u>



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Q. What position did Empire take?

A. According to Mr. Lyons testimony, Empire proposed to cap both the Residential and Large Power rate increases at 95% of the overall rate increase request. General Power, Transmission Service, Total Electric Building, and Private Lighting rates were increased at 100% of the overall rate increase request. The remaining revenue neutral deficiency shift was assigned to all other rate classes in proportion to their current revenues. This is restated in graphical form from Mr. Lyons testimony in Table 7:

Table 7: Empire's Recommended Revenue Increase by Rate Class

Rate Class	Proposed Revenues	Current Revenues	Increase $	Increase %
RG-Residential	$ 314,277,199	$ 293,097,843	$ 21,179,357	7.2%
CB-Commercial	63,270,070	57,708,886	5,561,184	9.6%
SH-Small Heating	14,251,189	12,998,567	1,252,622	9.6%
GP-General Power	129,577,749	120,418,306	9,159,443	7.6%
TS-Transmission Service	7,973,615	7,409,985	563,630	7.6%
TEB-Total Electric Bldg	54,467,748	50,617,594	3,850,153	7.6%
PFM-Feed Mill/Grain Elev	109,226	99,625	9,601	9.6%
LP-Large Power	114,776,031	107,041,195	7,734,836	7.2%
MS-Miscellaneous	22,039	20,102	1,937	9.6%
SPL-Municipal St Lighting	4,417,117	4,028,871	388,247	9.6%
PL-Private Lighting	4,973,992	4,622,396	351,596	7.6%
LS-Special Lighting	109,357	99,745	9,612	9.6%
Total Company	**$ 708,225,333**	**$ 658,163,117**	**$ 50,062,217**	**7.6%**

Q. Did Empire put out different class allocations in other filed testimony?

A. Yes. In Schedule ZQ-01 Empire witness Zachery Quintero included different increases across customer classes with and without Storm Uri costs across each customer class.[25] I am operating under the assumption that the Company's Class Cost of Service witness is the appropriate witness to opine on the Company's recommendation for class cost of service allocations.

[25] See GM-6

Q. What position did MECG take?

A. MECG took the position that the Company's CCOS study determined that LP and TS classes should get decreases of 3.5% and 10.3% respectively. MECG asserts average industrial rates are not cost competitive with state, regional and national industrial averages. MECG also relied heavily on Commission orders in 2014 and 2016 cases and noted that the Commission could not rely on any study from the 2019 case.

MECG placed an emphasis on correcting an alleged "residential subsidy" and suggested that because Storm Uri costs would be happening outside of this rate case, that a 25% revenue neutral shift was appropriate with revenue neutral shifts described as follows in Table 8.

Table 8: MECG Revenue Neutral Adjustments at Present Rates

Rate Class	Current Base Revenues	Revenue Change to attain Equal ROR	% Base Rate Revenue Neutral Increase @ equal ROR	25% Movement Towards COSS	Revenue Neutral Percent Change in Current Base Revenues
RG-Residential	$216,633,250	$41,926,713	19.35%	$10,481,678	4.8%
CB-Commercial	$43,153,741	($2,264,601)	-5.25%	($566,150)	-1.3%
SH-Small Heating	$9,356,502	($194,641)	-2.08%	($48,660)	-0.5%
GP-General Power	$82,426,006	($16,778,358)	-20.36%	($4,194,589)	-5.1%
TS - Transmission Service	$4,397,771	($1,328,124)	-30.20%	($332,031)	-7.5%
TEB-Total Electric Bldg	$35,162,635	($8,333,195)	-23.70%	($2,083,299)	-5.9%
PFM-Feed Mill/Grain Elev	$78,273	($16,018)	-20.46%	($4,005)	-5.1%
LP-Large Power	$67,285,606	($12,904,355)	-19.18%	($3,226,089)	-4.8%
MS-Miscellaneous	$14,032	$5,250	37.41%	$1,312	9.4%
SPL-Municipal St Lighting	$2,177,563	$754,474	34.65%	$188,618	8.7%
PL-Private Lighting	$3,983,179	($1,243,880)	-31.23%	($310,970)	-7.8%
LS-Special Lighting	$80,357	$376,735	468.83%	$94,184	117.2%
Company Total	$ 464,748,916	$0		$0	

Q. Is MECG proposing a revenue neutral shift of 117.2% to Special Lighting?

A. MECG's testimony contains a footnote on this point stating, "The revenue neutral change for LS-Special Lighting would need to be managed within the overall lighting class." I am not entirely sure what that means.

Q. What position did Staff take?

A. Staff recommended that the rate increase be allocated to the classes as an equal percentage increase.

Q. What is your recommendation?

A. There is a great deal of uncertainty surrounding what exactly the revenue requirement will be in the case. To be clear, presently the Storm Uri costs *are* in this case. I can agree with MECG in that its clients are paying well above state, regional and national averages; however, this is true for all classes. And this is before the requested rate increase or Storm Uri costs are factored in. My direct testimony discussed at length the poor results from J.D. Power's residential customer satisfaction survey that found only one other utility in the U.S. with worst results. I would also note that inflation is at a 30-year high and there is a still a large degree of uncertainty surrounding the ongoing COVID pandemic. In light of these considerations, I have a difficult time recommending any revenue neutral shift in this case as I believe the principle of gradualism trumps all considerations given the aforementioned facts. As such, similar to the position I took in rebuttal in the last Empire rate case, I am tentatively aligned with Staff's initial recommendation, but I reserve the right to amend my recommendation as more information is presented.

VI. RATE DESIGN

Time-of-Use Rates

Q. What are parties' positions on time-of-use ("TOU") rates?

A. Both the Company and Staff filed widely different recommendations regarding TOU rates in this case. The Company wants to offer a limited, risk-free pilot program. Staff would like to migrate all residential customers to a TOU offering and offered four different options for the Commission's consideration. I respond to both positions in turn.

Q. What do you mean by a risk-free TOU rate?

A. Residential and Commercial (but not Large Power) Customers who participate in the TOU offering will be refunded any amount over what would have been billed under the standard tariff rate.

Q. Can anyone participate?

A. No. For residential customers the Company is proposing to limit the rate to no more than 500 customers and for commercial customers no more than 200. For Large Power, Empire is proposing to limit the rate to no more than 3 current LP customers that have a maximum demand of 5 MW or greater during the previous 12-month period.

Q. Do you support the Company's position?

A. No. The Company is seeking a return on and of its large capital investment in AMI meters in this case, but limiting the benefits to less than ½ of a percent for its customers (500 = 0.38% of the residential class). I was crystal clear in Empire's 2019 rate case that the Company needed to have its hardware, software, and customer education plan already in place and ready to roll-out TOU rates for all customers before OPC would support recovery. As such, if the Company is unable to offer TOU to all of its customers I recommend that the Commission disallow the return on for the AMI capital investments. I believe a grave disservice has been taking place (for a number of years now) for Evergy Metro and Evergy West customers in that they have been paying a return on and of AMI investments without any of the espoused benefits of TOU rates that were promised. I will not recommend deviating from that position again.

Q. What is Staff recommending regarding TOU rates?

A. Staff has offered up four different residential TOU options ranging in difficulty of promotion/understanding. The Staff also recommended that an opt-out provision not be offered unless the residential revenue requirement ordered in this case is at the level requested by Empire.

The options can be generally described as follows:

1. Pay an on-peak (6am to 8:59pm) premium $0.0106
2. Receive an off-peak (9pm to 5:59am) discount $(0.007761)[26]
3. Both on-peak premium and off-peak discount with winter declining blocks eliminated but electric space heating customers held constant to the current non-summer first block.
4. A more complex approach (Super On/Off and On/Off Peak per season) in which Staff tentatively suggests a "hold harmless" provision should be in place.

Staff's preferred order of preference is as follows: 2, 1, 3, and 4.

Q. Do you support the Staff's position?

A. Yes. Both option 1 and 2 should have minimal impact and would serve as good introductory TOU rates to residential customers. I highly recommend that the Commission order the Company to prepare its customers and offer up options 3 and 4 (or something very similar) in the Company's next general rate case. Given the current poor residential customer perception of the Company, concerns over inflation and uncertainty surrounding COVID-19, I recommend that an opt-out provision be available to customers regardless of the residential revenue requirement.

Residential Customer Charge

Q. Generally, what is a customer charge?

A. A fixed charge to customers each billing period, typically viewed as intended to cover metering, meter reading and billing costs that do not vary with size or usage. Also known as a basic service charge or standing charge.

[26] Both option 1 and 2 maintain a winter declining block rate.

Q. What are the various parties' positions on Empire's customer charge for its residential customers?

A. Empire recommends a 23% increase in its residential customer charge, which would raise it from $13.00 to $16.00. Staff recommends the $13.00 residential customer charge remain as is.

Q. In your opinion what kinds of costs should be recovered in a customer charge?

A. To state the obvious, customer-related costs should be recovered through the customer charge. These should be costs sensitive to connecting a customer irrespective of the customer's load (e.g., meter, billing). That is, customer-related costs exist even when kW demand and kWh are zero.

When having one or more customers on the system raises the utility's cost regardless of how much the customer uses (billing is an example), then a fixed charge to reflect that additional fixed cost the customer imposes on the system makes perfect economic sense. Utilities can justify a customer charge to recover these basic costs because they are directly related to the number of customers receiving an essential monopoly service. The idea that each household has to cover its customer-specific fixed cost also has obvious appeal on grounds of equity. This is contrasted with system-wide "fixed" costs, such as maintaining the distribution network, which do not change if one customer were to drop off the system.

Q. How does increasing and decreasing a residential customer charge impact the customers?

A. An increase to the customer charge positively impacts above-average use customers and negatively impacts below-average use customers. On the other hand, a decrease to the customer charge positively impacts below-average use customers and negatively impacts above-average use customers.

Stated differently, "in general," a lower customer charge tends to favor, low-income customers, renters, and customers who have invested in energy efficiency and solar (or plan on investing in those items).[27] In contrast, a higher customer charge favors affluent customers and electric space-heating customers. It also provides greater revenue certainty for the utility.

Q. Is OPC concerned with the frequency of requests to increase residential customer charges?

A. Yes. OPC strongly believes the customer charge should not be a conduit to address the Company's perceived external threats and certainly not at the expense of those who can least afford to lose further control over their financial lives. However, beyond low and fixed-income ratepayers, the next obvious subset of ratepayers who are unfairly penalized by an increased customer charge are those who have invested time and money in being efficient, conservative and environmentally responsible.

This is because increased customer charges offset the financial savings of any previous efficiency actions and erode the incentive to improve appliances or better insulate their home moving forward. Ratepayers who are considering making investments in energy efficiency measures will have longer payback periods over which to recoup their investments. Increasing the customer charge distorts these pricing estimates and would cancel out the energy saved by Empire's energy efficiency programs to date. This same logic applies to distributive generation (rooftop solar).

If a ratepayer considers making a large-scale capital investment they should be cognizant of the risk involved with that purchase. In some ways, this is no different than any other long lived investment. For example, if you pay extra for an electric car, you run the risk that gas prices fall after you buy the car and your investment will not pay off. What's different about distributed generation or energy efficiency is much of the risk is subject to Commission orders. With most financial risks, there's a chance the underlying prices will go up or down 5% but a much smaller chance that they'll change by over 50%. However, this is exactly

[27] I say in general, as there will be affluent customers who have below average use and low-income customers with above-average usage—in particular, electric space heating customers.

the sort of risk ratepayers who have elected to become more efficient are faced with whenever a rate case docket is opened.

If the residential customer charge is raised, ratepayers who have made investments in energy efficiency or distributed generation will have longer payback periods over which to recoup their investments if any of those fixed monthly customer charges were accepted. Despite the increased customer charge tactic largely being abandoned by utilities throughout the country, ratepayers who made good-faith investments are still exposed to future regulatory rate design departures or rulemaking decisions that could have an adverse impact on their past decisions to proactively take control of their bills.[28]

Q. What about Mr. Lyons' argument that electric cooperatives in Missouri have higher customer charges?

A. This is a highly misleading argument. Mr. Lyons presented a seemingly random list of Missouri electric cooperatives and investor-owned utilities residential customer charges.[29] That list is reprinted in Table 8 below.

[28] Trabish, H.K. (2015) Beyond fixed charges: 'Disruptive Challenges' author charts new utility path. *Utilitydive*. https://www.utilitydive.com/news/beyond-fixed-charges-disruptive-challenges-author-charts-new-utility-pat/408971/

[29] I say random, because he selects six cooperatives that are nowhere near Empire's location (Farmers, Citizens, CO-MO, Platte-Clay, Callaway, Boone, and Black River) and omits six cooperatives adjacent (or closer) to Empire (Barton, New Mac, Barry, Sac Osage, Se-Ma-No, Howell-Oregon and Intercounty).

Table 8: Reprint of Mr. Lyons Missouri Customer Charge Survey[30]

Empire District Electric (MISSOURI) Customer Charge Survey	Residential
Union Electric Co - (MO)	9.00
KCP&L Greater Missouri Operations Co.	11.47
Kansas City Power & Light Co	11.47
Webster Electric Coop	24.00
Southwest Electric Coop, Inc	25.00
Black River Electric Coop - (MO)	25.00
Platte-Clay Electric Coop, Inc	25.38
Ozark Border Electric Coop	26.00
Farmers Electric Coop, Inc - (MO)	26.00
Laclede Electric Coop, Inc	27.00
Ozark Electric Coop Inc - (MO)	27.50
Citizens Electric Corporation - (MO)	29.00
Boone Electric Coop	29.95
Carroll Electric Coop Corp	30.00
White River Valley El Coop Inc	31.00
Osage Valley Elec Coop Assn	31.00
Co-Mo Electric Coop Inc	35.00
Callaway Electric Cooperative	39.00
Average	$ 25.71

Mr. Lyons omits the number of customers served by each utility thus distorting the "average" customer charge. Based on 2020 data from the U.S. Energy Information Administration ("EIA") forms EIA-861 I have supplemented Mr. Lyons' table with the reported number of residential customers served by each utility and averaged the mean residential charge across the roughly 2 million customers included in his table. This results

[30] Case No. ER-2021-0312 Direct Testimony of Timothy S. Lyons p. 35, 7.

in an "average" reduced amount of $12.40 for a total of $13.31, or $0.31 more than the current Empire residential customer charge. The results are shown in Table 9 below.

Table 9: Mr. Lyons' Missouri Customer Charge Survey with Number of Customers

Company	Number of Customers	Customer Charge	Patronage Capital
Ameren Missouri	1,071,999	$9.00	No
Evergy West	291,923	$11.47	No
Evergy Metro	262,729	$11.47	No
Empire	**133,019**	**$13.00**	**No**
Webster Electric	17,744	$24.00	Yes
Southwest Electric	39,423	$25.00	Yes
Black River Electric	20,937	$25.00	Yes
Platte-Clay Electric	22,209	$26.00	Yes
Ozark Border	32,848	$26.00	Yes
Famers Electric	12,172	$27.00	Yes
Laclede Electric	33,800	$27.00	Yes
Ozark Electric	30,812	$27.50	Yes
Citizens Electric	24,836	$29.00	Yes
Boone Electric	32,128	$29.95	Yes
Carroll Electric	11,472	$30.00	Yes
White River Valley	37,545	$31.00	Yes
Osage Valley	15,587	$31.00	Yes
Co-Mo Electric	29,647	$35.00	Yes
Callaway Electric	12,209	$39.00	Yes
	2,133,039	**$13.31 average**	**Not Empire**

Q. What should the Commission note from the two different tables being presented?

A. That Mr. Lyons' table attempts to distort the argument of a "reasonable" residential customer charge by including a list of cooperative utilities with different business models with that of investor-owned utilities. This is an apples-to-oranges comparison because cooperatives are non-profits.

Q. Table 9 includes a column titled "Patronage Capital". What does that mean?

A. Patronage capital is a unique feature designed solely for cooperative members and accentuates the difference between the two types of business models (i.e., the for-profit investor and the non-profit member). Under the cooperative model, any profit that is made is ultimately returned to its members (customers) at some point.[31] The profit return process is known as "patronage capital" and is what is left of the revenue after all of the expenses have been paid in a given year. The capital is divided by all members based on the amount of energy they used and is paid to members over the retirement basis whether or not they were or are members for the entire 20-25 year-period.[32]

Empire's customers receive no such benefit. The profit generated by Empire are returned to its shareholders.

Providing reliable power at affordable costs (i.e., covering the cost of service) is the sole job of cooperatives; whereas making as much profit as possible is clearly Empire's primary concern as evidence by their actions in this and recently filed cases.

Q. What is your recommendation regarding Empire's residential customer charge?

A. Historically, distribution costs have been recovered through the energy charge in light of economic and public welfare characteristics. More recently, an emphasis on public policy goals focusing on energy efficiency and environmental stewardship have reinforced those decisions. I see very little reason to deviate from that rationale. This is especially true in light of Empire's pending MEEIA application.

I recommend that the Commission keep Empire's residential customer charge at $13.00. Whether or not the residential customer charge needs to be lowered in light of Empire's AMI investment is a matter that merits serious consideration in future rate case proceedings.

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[31] This is known as the "retirement basis" and it can vary considerable across co-operatives (e.g., every year, every five years, etc…)

[32] See also Barton County Electric Patronage Capital https://www.youtube.com/watch?v=K0_ib3yw8JM

Decoupling Tracker

Q. Why is Empire proposing a decoupling tracker along with its TOU rate?

A. To provide revenue certainty for shareholders.

Q. Can Empire propose a decoupling tracker?

A. Senate Bill 564 allows utilities to elect Plant-In-Service Accounting *or* revenue decoupling. Empire elected the latter in its last rate case and was denied the provision, in part, because of the large number of estimated bills that distorted the Company's billing determinants and called into question the accuracy of any decoupling mechanism.

Since then, Empire has now elected Plant-In-Service Accounting ("PISA"). Effectively, the only difference between the SB 564 decoupling option and what Empire is proposing is the ability for the Company to collect "lost" revenues outside of a rate case. Empire is proposing a tracker which provides the same end result—shareholder risk reduction through revenue certainty. Empire wants to have it both ways. The Commission should reject this request out-of-hand as the General Assembly only allowed for one shareholder risk reduction track.

Class Consolidations

Q. What is Staff's recommendation regarding class consolidations?

A. Staff recommends consolidation of:

- Commercial Building ("CB") and Small Heating ("SH") rate schedules into a new "Small General" rate schedule;
- General Power Service ("GP") and Total Electric Building Service ("TEB") into a Medium General Service or into two new rate schedules Large General Secondary Service and Small General Primary Service; and to eliminate
- The Feed Mill and Grain Elevator Service ("PFM") rates and move them into Medium General Service (or the appropriate voltage-specific rate schedule)

Staff makes these recommendations based on available data to better align cost causation.

Q. Do you support these recommendations?

A. Based on my review of Staff's work papers I tentatively support these recommendations, but fall short of a categorically supporting this movement until I hear the Company's response (particularly as it pertains to SH customers). I have no problem supporting the consolidation of the PFM rate into one of the three proposed voltage-specific rate schedules.

Renewable Energy Purchase Tariff

Q. What is Empire's proposed Renewable Energy Purchase ("REP") tariff?

A. Empire is proposing a new schedule, Renewable Energy Purchase ("REP"), in order to comply with the Stipulation and Agreement in EA-2019-0010. The REP schedule will allow non-residential customers to purchase RECs to offset the carbon emissions of up to 100% of their total monthly billed electricity consumption in increments of 25% (limited by the availability of RECs) at the average weighted price for the Company's REC sales for the previous calendar year. Proceeds from REC sales will be credited to customers through the FAC rider. The Company is proposing a minimum term of one year, which will automatically renew at the end of each term unless specifically requested with at least 30 days' notice.

On a quarterly basis, the Company shall perform a review of the previous three months' average weighted price ("Quarterly Review") for the Company's REC sales to the schedule's REC Rate. If the REC Rate is outside a five percent threshold as compared to the Quarterly Review, the REC Rate will be recalculated as the weighted average price for the most recent 12-month ending period. This updated REC Rate shall become effective with the first billing cycle of the following month.

Q. What recommendations did Staff propose to the REP?

A. Staff recommends that any REP schedule approved in this case incorporate the provisions intended for the service agreement. Additionally, Staff recommends a percentage cap on the number of RECs available to the program to ensure REC availability for the statutory RES standard is prioritized.

Q. What is a REC?

A. A Renewable Energy Credit ("REC") is a certificate corresponding to the environmental attributes of energy produced from renewable sources. RECs can be sold within compliance markets as a means to track progress towards and compliance with states' statutorily enabled Renewable Energy Standards ("RES") or in a voluntary markets for customers who wish to claim renewable energy actions. Buying RECs allows an entity to support renewable energy without having to install solar panels or wind turbines. RECs can be purchased in one state and applied for compliance in another state. For example, a REC generating facility can be located in Florida, where the actual power produced goes to the local grid in Florida, but the credit for the "renewable attributes" of that power would be purchased by a Missouri utility and used to meet the Missouri RES. Thus, the REC represents a "societal benefit" as well as a tradeable commodity.[33]

This is also known as an "unbundled" REC, as the energy produced from the REC is not physically delivered to the customers purchasing it.[34] The price of these RECs can vary greatly by resource type (e.g. wind, solar, hydro), from state to state and year to year, in part, due to a state's RES geographic sourcing conditions.[35] Importantly, one can purchase a REC and can "claim emissions reductions" even if they do not actually reduce their end-use at all—or even increase it. The purchase of a REC does not necessarily mean that "new"

[33] To prevent "double counting" (in this scenario) the renewable energy produced in Florida cannot be counted for renewable compliance purposes in Florida as the REC has been sold to Missouri.

[34] As opposed to a bundled REC which are tied to the purchase of electricity.

[35] That is, a state's Renewable Energy Standard can be drafted to count RECs on more narrowly defined areas. For example: only in the state, only in surrounding states, only in a given utilities ISO region, or more broadly, from anywhere in the United States. In Missouri, RECs can be purchased for compliance anywhere in the United States, but RECs purchased in Missouri can claim additional "adder" compliance value. Unbundled RECs are almost always less expensive than producing the energy through renewable resources.

renewable energy supply was created, often RECs are sold from existing renewable energy sources and can be "banked" for up to three years.

Q. Would the purchase of these RECs constitute "new" renewable energy supply or a bundled REC?

A. No. I am using the term "new" to mean a financial commitment made by third-party to enable a renewable to be created. Empire's wind investments are already up-and-running.

I also do not believe these RECs would be considered "bundled" because the developers have already received financing and constructed the project—the guaranteed revenue stream to cover the tax equity financing for this merchant generator is borne by captive ratepayers.

Q. Do you believe this will be a successful program?

A. I hope so, but I remain highly skeptical.

Q. Why?

A. People who voluntarily buy RECs want to know that they are getting "financial additionality." In other words, they want to know that their REC purchases are a helping to build clean energy projects that *wouldn't otherwise get built*.

Entering into a standalone REC agreement or an "unbundled" REC contract is inconsistent with the Corporate Energy Buyers' Principles.[36] An unbundled REC refers to RECs that are sold, delivered, or purchased separately from electricity. They are merely a tradeable, market-based instrument that represent the legal property rights to the "renewable-ness" not the actual physical delivery of electricity to customers purchasing the power. This is not "additional" renewable energy. An important tenant of the 4th principle:

> 4. Access to new projects that reduce emissions **beyond business as usual**.
>
> We would like our efforts to result in new renewable power generation. Pursuant to our desire to promote new projects, ensure our purchases add

[36] World Resource Institute (2021) Corporate Renewable Energy Buyers' Principles. https://www.wri.org/publications/corporate-renewable-energy-buyers-principles

> new capacity to the system, and that we buy the most cost-competitive renewable energy products, we seek the following:[37]

Again, these wind farms have already been built. The time to raise this issue with customers would have been before/during or immediately following the "decisional direction" and CCN dockets the Company filed over these wind projects. As it stands, this "unbundled" RECs has been viewed by some environmentalists as a form of greenwashing.

Greenwashing occurs when a corporation or entity spends time and money marketing themselves as "green" or environmentally friendly, when, in reality, they are not realistically reducing their environmental impacts to the extent that they appear to be. While unbundled RECs are not necessarily greenwashing, there are *much* better options to ensure that their facility is not contributing to climate change by using fossil fuels for energy production.

Q. Did you point this out in past testimony?

A. Yes. In Case No: EO-2019-0010 my affidavit in opposition of the non-unanimous stipulation and agreement stated:

> As part of the S&A, Empire has agreed, as part of its next rate case, to propose a green tariff option to corporations that wish to demonstrate compliance with self-imposed sustainability commitments. Interested non-residential customers could elect to pay an additional premium in exchange for a portion of the Renewable Energy Credits ("RECs") received from the Wind Projects.
>
> It is OPC's position that this commitment is only aspirational and will likely not result in the intended outcome—convincing corporate entities to shoulder some of the associated costs (risk) in exchange for RECs. . . .
>
> For this provision to be substantively relevant, the germane green corporate buyers would already be committed to bearing these future costs.[38]

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[37] Ibid.

[38] Case No. EA-2018-0092 Affidavit of Geoff Marke in Opposition of the Non-Unanimous Stipulation and Agreement p. 20-22.

In Case No: EA-2019-0010 I concluded my surrebuttal testimony on the topic including the following Q&A:

> **Q. Putting aside consumer protections, are Ameren Missouri, KCPL and GMO's Green Tariff's comparable to Empire's applications here in terms of risk exposure?**
>
> A. No. Even without the consumer protections agreed to in the Green Tariff cases, those applications were predicated on actual contractual committed demand for the service before it could move forward. In contrast, Empire models its application on an assumed demand for this intermittent generation materializing in the future at a premium price. This difference cannot be understated.[39]

Q. Do you believe commercial and industrial customers will participate in this offering?

A. I hope so, but I am highly skeptical. Empire had several years to work on securing offset costs from commercial and industrial customers in the form of future RECs before the wind farms were built. They failed to do that and captive customers will now pay more as a result. This current tariffed offering is likely too little, too late to have any material offsetting impact. Instead it serves as yet another lost opportunity due to managerial mismanagement.

Q. Do you support Staff's recommendations?

A. Yes.

Q. Are you recommending any cost disallowance due to Empire's failure to attempt to seek offsetting costs from commercial and industrial customers in the form of REC commitments before its wind farms were built?

A. I recommend that the Commission consider this lapse in managerial prudence in setting the Company's return on equity.

[39] Case No. EA-2019-0010 Surrebuttal Testimony of Geoff Marke p. 22, 4-10.

Q. Does this conclude your testimony?

A. Yes.