

MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT



**A WORKING CASE TO CONSIDER
POLICIES TO IMPROVE ELECTRIC UTILITY REGULATION**

FILE NO. EW-2016-0313

OCTOBER 17, 2016

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I. Executive Summary

On June 8, 2016, the Commission issued an Order Opening a Working Case to Consider Policies to improve Electric Utility Regulation, in which it invited interested stakeholders to submit written suggestions for policy changes and directed Staff to submit a written report to the Commission no later than October 17, 2016, describing and evaluating the submitted suggestions, and offering its recommendations for any actions to be taken by the Commission. On June 22, 2016, Chairman Hall filed a Notice of Policy Initiatives for Stakeholder Consideration. Comments and responses were received in the docket and Staff held a workshop on September 13, 2016 to gather additional information.

The utilities allege there is a problem with Missouri's existing regulatory framework, which sets rates for future periods based on historical data creating regulatory lag, "often spanning a period of years".¹ Consumer groups claim that overarching metrics indicate the current regulatory framework is working, and regulators and legislators should be hesitant in making sweeping changes. Much of the utilities' concern appears to be related to whether the electric utility will earn its authorized return, and how that affects management decisions to invest in infrastructure beyond what is necessary to provide safe and adequate service. To gain a better understanding of the utility regulatory concerns and investment needs, Staff met with utility representatives on several occasions. As discussed in further detail below, while Staff is not convinced a problem exists to the level raised by the utilities, the myriad of comments suggest some degree of policy or legislative reform could be beneficial to the Missouri regulatory process and, ultimately, Missouri consumers. Many of the proposed investment opportunities may provide improved reliability, safety or security, but more likely, will automate the Missouri grid using the latest technologies and changing consumer needs. Therefore, Staff

¹ Initial Comments of Ameren Missouri, July 8, 2016, page 2.

recommends some reform to the current regulatory environment. Staff is not opposed to the following approaches if in conformity with the general ratemaking principles and under the specific conditions outlined later in this Report: shortened rate case processes, a continued true-up period, certain trackers/riders, interim rates, partially forecasted test years that are true-up within the pendency of a rate proceeding, an electric infrastructure system replacement surcharge (“ISRS”), an electric rate case adjustment proceeding process, decisional pre-approval with post-construction review, a grid modernization incentive mechanism, net metering and solar modifications, security and diversity supply modifications, alternative financial instruments, a low income rate or additional residential rate classes, shared rate case expense. While not specifically recommended, any legislative changes should allow Commission discretion as to the use of regulatory reform based on a thorough review of evidence before it. This report provides Staff’s analysis and specific recommendations related to these general methodologies and concepts.

II. Missouri’s Regulatory Environment

A. Is there a problem that needs to be addressed?

Utility Perspective

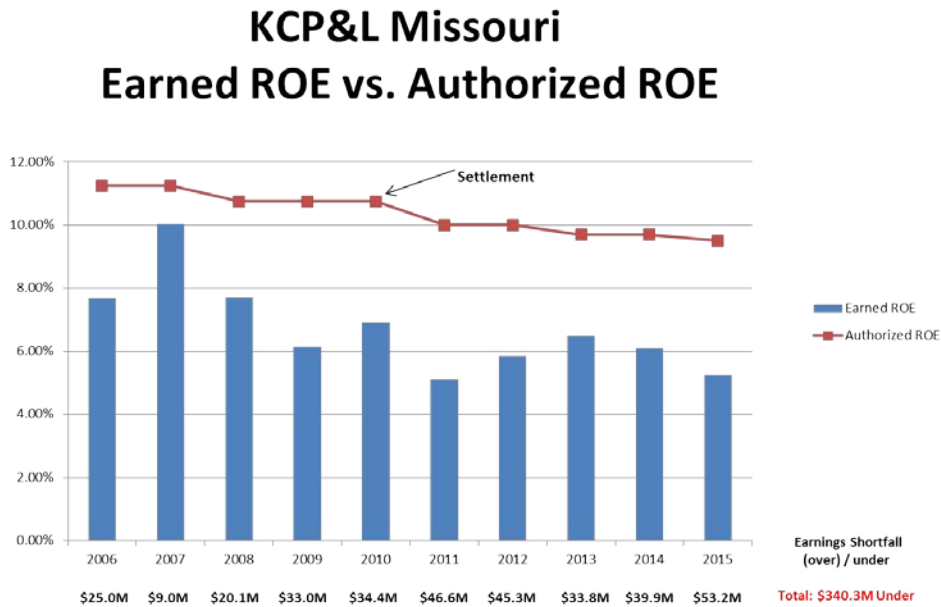
Ameren Missouri, in its comments², states,

[T]he fundamental problem with Missouri’s existing regulatory framework is simple: Missouri sets rates for future periods based on historical data. Specifically, Missouri uses costs and revenues from an historical test year, with some updates through a true-up period, to set future rates. But in most cases, the test year ends more than a year before new rates take effect, and even the true-up period ends at least five or six months before the effective date of new rates. As discussed further [in the comments], utilization of a true-up period, even if it is within five or six months of the effective date of new rates, still means that there will be tremendous regulatory lag associated with capital investments in the electric utility’s system, often spanning a period of years, not months.

² Unless otherwise noted, all references to stakeholder statements are references to that stakeholder’s Initial Comments.

The impact of this process may be obvious, but it is worth stating. If the electric utility experiences inflation, particularly with flat or declining load growth, setting rates based on historical expenses will cause the utility's rates to be inadequate to cover its future expenses. Such a shortfall can never be made up. It is a permanent loss to the utility.

Kansas City Power & Light Company ("KCP&L), in its presentation³ at the File No. EW-2016-0313 September 13, 2016 Workshop ("workshop"), identified declining usage, investment and depreciation expense ratio, its earned return on equity (ROE) compared to its authorized ROE, transmission costs, property tax issues and revenues as significant problem areas. In its presentation, KCP&L presents the following chart on earned ROE vs authorized ROE⁴:



³ "Is there a problem that needs to be addressed?" EFIS Item No. 50.

⁴ Staff has not verified the data.

Ameren Missouri, in its September 23 response to Staff questions⁵, comments that KCP&L’s chart provides “a stark illustration of the deficiencies of Missouri’s regulatory framework for a utility that aggressively invests in its infrastructure”. Ameren Missouri continues that a review of Ameren Missouri’s investments from 2007 through 2011 tells a different, but similar story.

From 2007 through 2011 Ameren Missouri invested at approximately 2X its depreciation rate and, like KCP&L, Ameren Missouri never came close to earning its authorized return. Beginning in 2011, Ameren Missouri reduced its capital investment levels, and by 2015 Ameren Missouri’s ratio of capital investments to depreciation had fallen to 1.37—in the bottom 1/8th of electric utilities in the country—while it began earning returns closer to its authorized return. Although actual returns in any given year are influenced by a variety of factors, including weather and nuclear plant outages, reducing capital investments, along with reducing expenses, have been necessary to provide Ameren Missouri with any reasonable opportunity to earn its authorized return.

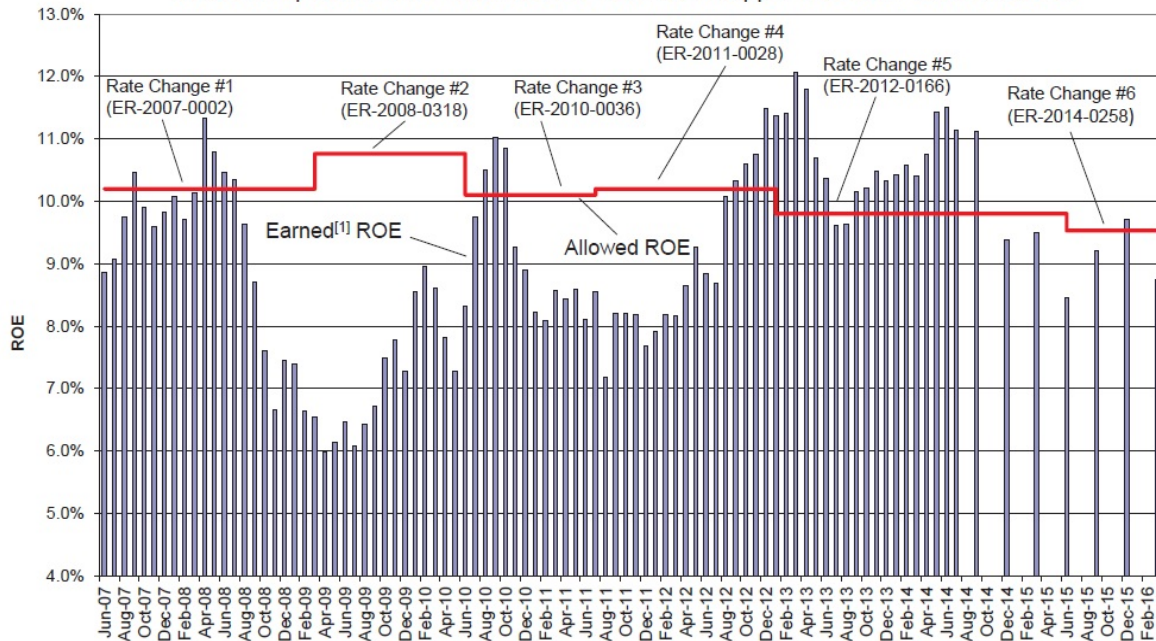
Ameren Missouri, in its workshop presentation⁶, provided the following chart as illustrative of the comparison between Ameren Missouri’s allowed ROEs versus its earned ROEs.⁷

⁵ “The Critical Need to Replace Aging Electric Infrastructure and Build a Smarter and More Efficient Grid to Meet Customers’ Needs and Expectations”. EFIS Item No. 58.

⁶ “An example of what is happening...”. EFIS Item No. 47.

⁷ Staff has not verified the data.

Comparison of Ameren Missouri Earned^[1] ROEs and Allowed ROEs
 Reflects Four Rate Changes - *Not* Weather-Normalized
 Reflects Impact of FAC Prudence and Taum Sauk Upper Reservoir Disallowances



[1]: In addition to reflecting the impact of the FAC prudence and Taum Sauk upper reservoir disallowances, the earned ROE has been adjusted to account for company's absorption of the impact of the Taum Sauk plant being out-of-service from Dec. 2005 to April 2010.
 [2]: Last monthly report was prepared in July, 2014.

Staff Questions Related to Utility Investment Plans

On August 25, 2016, Staff filed a motion in this docket asking the Commission to order the investor-owned (“IOU”) utilities to respond to questions about the impact proposed regulatory changes would have on investment plans. On August 31, the Commission directed the IOUs to respond to Staff’s questions no later than September 23. The IOUs responded on September 23, 2016. The questions and IOU responses follow:

Question A: What investments are you not able to make under the current regulatory environment that you would be able to make if there was a change in ratemaking practices?

Ameren Missouri, in its response, noted that aging infrastructure needs to be replaced, representing:

- Ameren Missouri’s four baseload coal generation plants are on average almost 50 years old;
- Approximately half of Ameren Missouri’s substations are over 40 years old; and
- Ameren Missouri’s underground network serving downtown St. Louis has facilities that are 80 to 100 years old.

According to Ameren Missouri, “outdated policies impede electric service providers’ ability to ramp up their investments to address the aging energy infrastructure”. In addition to replacing aging infrastructure, Ameren Missouri states, the grid must be updated to meet customers’ needs and expectations, including such things as cleaner, intermittent resources from greater levels of renewable energy, Distributed Energy Resources (“DER”), bi-directional energy flows where utility and customer distributed resources provide energy and ancillary services, “self-healing” facilities to quickly restore service after an outage without human intervention, and interconnection of DERs and microgrids to the system. Ameren Missouri indicates,

In an environment of no electric sales growth and increasing investment needs, rates never reflect electric utilities’ true cost of service and losses are never made up. In this environment, limiting capital investment is necessary in order for an electric utility to earn its authorized return, which is at odds with the State of Missouri’s energy needs for the future.

More specifically, Ameren Missouri includes appendices of infrastructure projects it could undertake if regulatory lag were mitigated. Details of the projects are not repeated in this report, but Ameren Missouri provides the following summary of the appendices.

While beneficial incremental investments of \$4 billion over a ten-year period have been identified, we have presented a detailed plan for incremental infrastructure investment of \$1 billion over a five-year period to balance the need to address our aging infrastructure with related rate impacts. Additional projects of approximately \$1 billion could be accelerated in this five-year time frame should it be deemed appropriate. These investments will allow Ameren Missouri to implement the following customer beneficial projects:

- Accelerate the replacement of substations in excess of 40 years old to preserve and enhance reliability and enhance system security.

- Upgrade several substations to a modern design that increases resiliency when short circuits occur, provides isolation points for service restoration, and includes smart diagnostics and advanced relaying to detect and correct problems faster.
- Proactively replace underground cable to preserve and enhance reliability.
- Automate distribution facilities to minimize outages and enhance security.
- Replace Ameren Missouri's out-of-date meters with smart meters that provide customers modern service options that would facilitate much greater penetration of energy efficiency programs as well as peak load management programs. These programs will be critical as Ameren Missouri retires more baseload generating units and works to minimize the need to construct additional large energy centers.

The Empire District Electric Company ("Empire") responded that the current regulatory environment has forced it to make decisions "that were less than ideal." Empire indicates it has made all investments it "deemed reasonable and prudent and necessary for the provision of safe and reliable service." Empire explained that, "[d]uring periods of major capital expenditures for improvements, however, Empire believed it was necessary to delay certain other prudent expenditures." Empire provided an example where during the construction of Iatan 2, Empire found it necessary to delay replacing vehicles and equipment.

Kansas City Power & Light Company ("KCP&L) and KCP&L Greater Missouri Operations Company ("GMO") responded,

For the period of 2006-2015, KCP&L and GMO operated under a proactive capital expenditure policy and did not curtail capital projects due to the ratemaking practices used in Missouri which rely almost exclusively on historical data to set rates prospectively. KCP&L had made significant commitments under the Comprehensive Energy Plan ("CEP") that needed to be completed to serve current and future customer demand with reliable, cost-effective, and environmentally-compliant energy. These projects included the construction of the Iatan 2 coal-fired generating unit, environmental retrofits at Iatan 1, development of 100 MW of wind generation, environmental retrofits on Units 1 and 2 at La Cygne Generating Station, and system load reduction through various energy efficiency programs.

All four IOUs represent that demand for electricity is stagnant or declining adding to the regulatory issues in Missouri. According to the U.S. Energy Information Administration (“EIA”), excluding the Noranda Aluminum Smelter, Ameren Missouri demand is down both per customer and as total usage for the last several years. KCPL and GMO also show declining usage. Empire usage is down per customer, but that is made up by growth in number of customers.⁸ The following chart demonstrates this information.

	2011	2012	2013	2014	2015	2011-2015 Change	2012-2015 Change
<u>MWh</u>							
Empire	4,142,916	4,023,550	4,085,362	4,148,677	4,059,622	-2%	1%
KCP&L	8,747,836	8,580,716	8,562,163	8,554,331	8,432,160	-4%	-2%
KCP&L-GMO	8,194,746	8,080,313	8,179,781	8,195,101	7,970,618	-3%	-1%
Ameren Missouri	37,406,588	36,724,319	37,008,080	37,000,785	35,855,106	-4%	-2%
<u>Customers</u>							
Empire	147,219	148,280	149,175	149,769	150,549	2%	2%
KCP&L	271,446	270,990	271,314	273,512	275,805	2%	2%
KCP&L-GMO	312,684	313,345	314,907	317,720	318,150	2%	2%
Ameren Missouri	1,190,477	1,193,670	1,197,294	1,200,002	1,203,537	1%	1%
<u>Revenue (\$1,000)</u>							
Empire	\$ 418,957	\$ 416,041	\$ 435,819	\$ 456,324	\$ 450,475	7%	8%
KCP&L	\$ 758,639	\$ 763,205	\$ 812,622	\$ 824,706	\$ 866,464	12%	12%
KCP&L-GMO	\$ 724,548	\$ 726,394	\$ 761,526	\$ 802,845	\$ 745,004	3%	2%
Ameren Missouri	\$2,807,812	\$2,834,677	\$3,150,139	\$3,110,834	\$3,208,194	12%	12%
<u>Revenue/Customer</u>							
Empire	\$ 2,846	\$ 2,806	\$ 2,922	\$ 3,047	\$ 2,992	5%	6%
KCP&L	\$ 2,795	\$ 2,816	\$ 2,995	\$ 3,015	\$ 3,142	11%	10%
KCP&L-GMO	\$ 2,317	\$ 2,318	\$ 2,418	\$ 2,527	\$ 2,342	1%	1%
Ameren Missouri	\$ 2,359	\$ 2,375	\$ 2,631	\$ 2,592	\$ 2,666	12%	11%
<u>Revenue/MWh</u>							
Empire	\$ 101.13	\$ 103.40	\$ 106.68	\$ 109.99	\$ 110.96	9%	7%
KCP&L	\$ 86.72	\$ 88.94	\$ 94.91	\$ 96.41	\$ 102.76	16%	13%
KCP&L-GMO	\$ 88.42	\$ 89.90	\$ 93.10	\$ 97.97	\$ 93.47	5%	4%
Ameren Missouri	\$ 75.06	\$ 77.19	\$ 85.12	\$ 84.07	\$ 89.48	16%	14%
<u>MWh/Customer</u>							
Empire	28.14	27.13	27.39	27.70	26.97	-4%	-1%
KCP&L	32.23	31.66	31.56	31.28	30.57	-5%	-4%
KCP&L-GMO	26.21	25.79	25.98	25.79	25.05	-5%	-3%
Ameren Missouri	31.42	30.77	30.91	30.83	29.79	-5%	-3%

⁸ EIA data is based on actual, non-weather normalized sales.

During the same period, energy efficiency savings were reported for each utility, as provided in the chart below.⁹ In the chart that follows, the actual sales reported above are provided with an adjustment to include the energy efficiency savings. After adjusting for energy efficiency savings, the declines in usage are reduced.

	2011	2012	2013	2014	2015
	Energy Efficiency MWhs				
Empire	-	-	6,047	4,258	5,739
KCP&L	-	-	17,209	57,746	108,354
KCP&L-GMO	-	-	30,495	57,640	68,772
Ameren Missouri	-	-	338,705	361,914	457,347

	2011	2012	2013	2014	2015	2011-2015 Change	2012-2015 Change
	MWh Sales with Energy Efficiency						
Empire	4,142,916	4,023,550	4,091,409	4,152,935	4,065,361	-2%	1%
KCP&L	8,747,836	8,580,716	8,579,372	8,612,077	8,540,514	-2%	0%
KCP&L-GMO	8,194,746	8,080,313	8,210,276	8,252,741	8,039,390	-2%	-1%
Ameren Missouri	37,406,588	36,724,319	37,346,785	37,362,699	36,312,453	-3%	-1%

Question B: If the decision to make investment depends on the extent of the regulatory change, please provide information as to investments that will be made under various regulatory environments (e.g. performance-based rates, shortened rate cases, an electric infrastructure system replacement surcharge (“ISRS”), construction accounting/plant-in-service, trackers/riders, projected/partially-projected test year, interim rates, construction work in process (“CWIP”) in rate base, etc.).

Empire indicated, “[a]lthough the current regulatory environment is not preventing Empire from making required investments at this time...new regulatory approaches that lessen

⁹ Ameren Missouri, KCP&L, and KCP&L-GMO are compensated for reductions in sales due to utility-sponsored energy efficiency programs under mechanisms promulgated under the Missouri Energy Efficiency Investment Act.

the impact of regulatory lag could allow utilities to better accommodate changing customer needs and expectations, and could enhance the provision of clean, safe, and reliable electric service in Missouri.” Empire cites shortened rate cases, an electric ISRS, decoupling, trackers/riders, a projected/partially-projected test year, interim rates and CWIP as examples of regulatory changes that could improve the current regulatory environment.

In response to this question, KCP&L and GMO responded that regardless of the mechanism, providing a “realistic opportunity to achieve the authorized return on equity should be a fundamental goal of any utility regulatory construct.” KCP&L and GMO state, “Over the 10-year period of the CEP, KCP&L’s actual Missouri jurisdictional earnings fell short of its Commission-authorized return on equity by more than \$34 million per year, on average.”¹⁰ Under the current regulatory environment, KCP&L and GMO state that electric utilities will not have a reasonable opportunity to achieve the Commission authorized ROE if capital expenditures exceed annual depreciation expense by 200 percent or more. They propose that an electric ISRS, PISA, performance-based rates (“PBR”), trackers/riders and revenue decoupling are options that will allow the utility to earn its Commission-authorized ROE. KCP&L and GMO provide the following list of projects that could be pursued under a “proactive capital expenditure philosophy”:

- Downtown Kansas City, Missouri infrastructure improvements – includes a new Charlotte Street substation, expansion of the Terrace substation, new Truman substation, and related underground conduit and cable replacements to upgrade the aging assets serving downtown Kansas City;
- Distribution Automation/Smart Grid – includes expanded deployment of automated switches, reclosers, fault indicators, and other equipment to improve fault detection and location and enable automated reconfiguration of the grid;

¹⁰ No information was provided in KCP&L’s and GMO’s comments regarding GMO’s earnings.

- Downtown Kansas City and Plaza network renewal – replacement of aging secondary cables, connectors, transformers, network protectors, and other components to refurbish the aging secondary network system;
- Replace/rebuild aging substations – rebuild aging substations and upgrade to current standards. Approximately 45 50 MVA, 161/12 KV transformers with an average age over 40 years are still in service;
- Rebuild aging transmission lines – refurbishment of 161 KV and 69 KV lines, many of which are approaching 40-50 years or more since initial construction;
- Replace underground feeder and lateral (URD) cables – replacement of portions of the underground feeder cable system approaching 60-80 years of age, as well as more than 1,000 miles of direct buried URD cable that are approaching 40 years of age;
- Generation Infrastructure Improvements – improvement of facilities at generating stations, including roads, buildings, offices, HVAC systems, and structures such as maintenance shops and lab space. New construction/renovation of offices, maintenance shops, lab space, etc.;
- Upgraded Generation Computer Systems – deploy new systems for document management, drawing management, and maintenance management;
- Centralized Generation Monitoring System – add a centralized monitoring system to assist generation plants in monitoring performance and troubleshooting equipment;
- Replace aging components – replace or upgrade aging assets (Power Cables, Piping, etc.) that have been in service 30 or more years;
- Upgrades to Aging Combustion Turbines – upgrade equipment and controls, on older combustion turbines; and
- Winterization of Combustion Turbines – upgrade combustion turbine units to increase operating flexibility.

Ameren Missouri indicates there are many ways to implement policies that address “the disincentive to invest that is caused by excessive regulatory lag”, citing PBRs, formulaic rates, forward test years, infrastructure riders and PISA.

Consumer Perspective

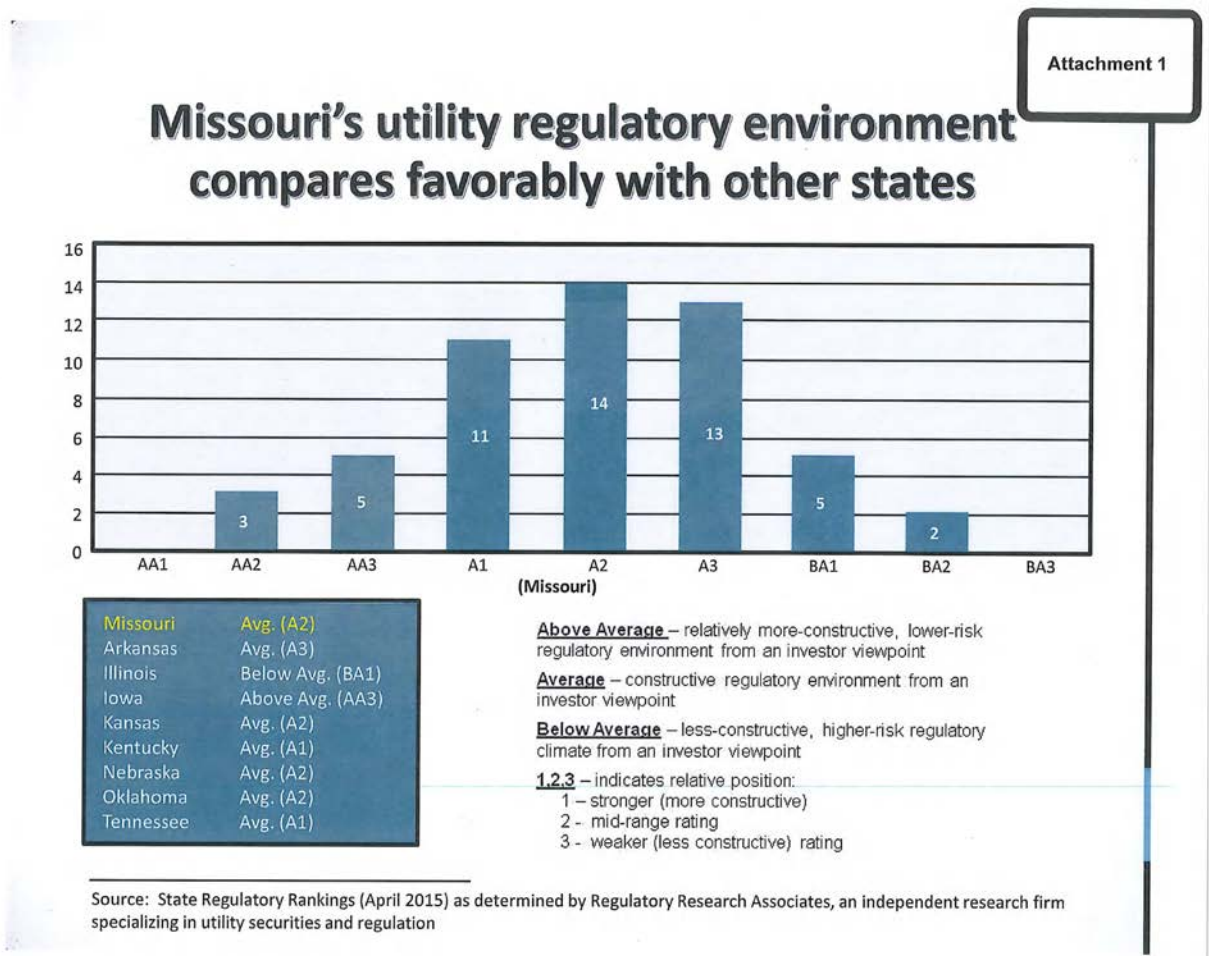
The Missouri Industrial Energy Consumers (“MIEC”) reminds the Commission that,

[I]t is important to recognize that the very heart of the regulatory process is the development of rates that are “just and reasonable.” Development of just and reasonable rates requires a balancing of many different objectives, including: adequate cost recovery opportunities for utilities; reasonable rates for consumers; rates that encourage economic utilization of electricity and other resources; and the provision of reliable, safe and adequate service by the utilities. Any changes made in the regulatory paradigm must consider the ability to continue to balance these interests in a way that is fair to all participants, and not tilted one way or the other.

In its October 10, 2016, Comments Supporting Staff’s Proposals and responding to the Utilities’ Answers to Commission Questions (“Comments Supporting and Responding”), MIEC states, “Excessive capital spending would unnecessarily increase electric rates, which would in turn harm ratepayers and cause statewide net job losses across economic sectors to the detriment of Missouri’s entire economy. MIEC cites “The Relationship Between Electricity Prices and Jobs in Missouri”, noting, “An electric rate increase of ten percent is likely to result in the loss of over 61,000 jobs, or approximately 1.8 percent of Missouri’s workforce”.

MIEC in its initial comments states that it is important to understand where Missouri ranks among other states in terms of its regulatory environment, and includes the following graph representing rankings determined by Regulatory Resource Associates (“RRA”), an independent research firm specializing in utility security. The graph represents that Missouri has an A2 rating. MIEC states, “...from an investor point of view, Missouri’s regulatory process is considered to be constructive”. MIEC continues that Illinois, “which is sometimes touted as being superior to Missouri because of ‘formula rates,’ is actually ranked BA1, two complete notches below Missouri from an investor’s perspective. MIEC includes additional attachments

that show the bond ratings and overall corporate ratings of Missouri utilities, indicating those ratings are “quite favorable”.



In response to KCP&L’s table depicting that it has not earned its authorized ROE, MIEC, in its Comments Supporting and Responding, notes that as a condition of the CEP, KCP&L agreed not to implement a fuel adjustment clause (“FAC”) until June 2015. MIEC continues that this would have a “dramatic effect on KCP&L’s earnings”, pointing out that in a Staff workshop comment, “actual ROEs of the other electric utilities, those having FACs, showed very different (positive) results over the same period”.

Finally, MIEC, in its Comments Supporting and Responding includes the following excerpt from a recent earnings call where Ameren’s Chief Executive Officer, in response to an analyst question regarding comparison of Illinois and Missouri reliability, stated:

[B]y and large Illinois has clearly made progress in improving the reliability as well as responding to outage duration as a result of the grid modernization project. By and large, what you are seeing between the two jurisdictions is that they are moving closer in terms of what their overall reliability and ultimate responsiveness to outages are. And so Illinois will continue to have specific metrics that they have to hit as part of the grid modernization act and will continue to pursue that. (Footnote omitted.)

This excerpt is relevant as Missouri and Illinois are often compared when considering the need for regulatory reform to address any problems in Missouri.

The Midwest Energy Consumers’ Group (“MECG”) states,

[O]verarching metrics indicate that the Commission, as well as the General Assembly, should be hesitant to engage in broad-brush change to the ratemaking mechanism. Specifically, the current paradigm: (1) encourages cost minimization; (2) results in strong Missouri utilities; and (3) provides for reliable service. All of these goals are achieved at rates that are largely competitive with national average electric rates.

To support its statements, MECG includes the following chart of credit ratings assigned by Standard & Poors:

Utility	Parent Company	Neighboring Jurisdiction	Rating
MidAmerican	Berkshire Hathaway	Iowa	A
Interstate Power & Light	Alliant	Iowa	A-
Duke Energy Kentucky	Duke Energy	Kentucky	A-
Kentucky Utilities	PPL	Kentucky	A-
Louisville Gas & Electric	PPL	Kentucky	A-
Oklahoma Gas & Electric	OGE Energy	Arkansas / Oklahoma	A-
Ameren Missouri	Ameren	Missouri	BBB+
Kansas City Power & Light	Great Plains Energy	Missouri / Kansas	BBB+
KCP&L Greater Missouri Operations	Great Plains Energy	Missouri	BBB+
Ameren Illinois	Ameren	Illinois	BBB+
Kansas Gas & Electric	Westar	Kansas	BBB+
Southwestern Electric Power	AEP	Oklahoma	BBB
Empire District Electric	None	Missouri / Kansas / Oklahoma / Arkansas	BBB
Commonwealth Edison	Exelon	Illinois	BBB
Appalachian Power	AEP	Tennessee	BBB
Kentucky Power	AEP	Kentucky	BBB
Entergy Arkansas	Entergy	Arkansas	BBB
Public Service Company of Oklahoma	AEP	Oklahoma	BBB

MECG further states that shareholders of the utilities have benefitted because they have seen stock prices increase at a rate that outpaced the Dow Jones industrial average. As additional support for the strength of Missouri utilities, MECG cites merger and acquisition activity. MECG also references a January 13, 2016, JD Power Electric Utility Business Satisfaction survey where Ameren Missouri and KCP&L came in first and second in customer satisfaction for quality and reliability.

On September 23, MECG submitted Reply Comments addressing concerns raised by Ameren Missouri at the September 13 workshop. During the workshop, Ameren Missouri suggested that instead of a comparison to the Dow Jones Industrial Average, MECG should have made a comparison to the Dow Jones Utility Average (“DJUA”). In its Reply Comments, MECG submitted the suggested comparison. According to MECG, the analysis indicates that Missouri utilities’ stock prices perform well when compared to the DJUA or against individual electric utilities that make up the composite index. MECG submits the following table.

Utility	Ticker	5 Yr Stock	Utility	Ticker	2 Yr Stock
NiSource	NI	201.69%	NiSource	NI	64.23%
Edison International	EIX	112.09%	Consolidated Edison	ED	38.32%
American Electric Power	AEP	79.85%	PG&E	PCG	37.34%
Empire District Electric	EDE	75.34%	Empire District Electric	EDE	36.82%
Ameren	AEE	68.10%	Ameren	AEE	32.35%
Dow Jones Utility Average	^DJU	64.92%	Edison International	EIX	31.85%
Dominion Resources	D	62.64%	American Electric Power	AEP	26.12%
PG&E	PCG	56.67%	Dow Jones Utility Average	^DJU	25.98%
Duke Energy	DUK	47.17%	Southern Company	SO	22.62%
Great Plains Energy	GXP	46.13%	Public Service Enterprise Group	PEG	18.85%
Consolidated Edison	ED	41.61%	Duke Energy	DUK	12.09%
Public Service Enterprise Group	PEG	35.15%	Dominion Resources	D	11.91%
Southern Company	SO	30.51%	Great Plains Energy	GXP	9.91%
AES Corp	AES	26.82%	Exelon	EXC	6.03%
CenterPoint Energy	CNP	23.05%	FirstEnergy	FE	1.15%
Exelon	EXC	-17.78%	CenterPoint Energy	CNP	-0.95%
FirstEnergy	FE	-19.05%	AES Corp	AES	-9.08%

Source: Google Finance for period ended close of business September 21, 2016

The Office of the Public Counsel (“OPC”), in its September 23, 2016, Additional Comments, includes the following:

Think about the following: Ameren Missouri (“Ameren”) said two years ago publically that the Clean Power Plan (“CPP”) will cost ratepayers \$4 billion. Two weeks ago, the *St. Louis Post-Dispatch* ran a story about the circuit courts upcoming \$1 billion dollar ruling on Rush Island. It should be noted that ruling has not been made in this case as of the writing of these comments. Ameren's IRP says they have of \$1.8 billion in known environmental costs. None of those billion dollar projections overlap. (Footnote omitted.)

OPC continues:

OPC...is uncertain as to why [Ameren Missouri] and the other investor-owned utilities seek reform that has the potential to cause more costs for ratepayers as well as increase the level of complexity faced by lawmakers and policymakers.

Finally, OPC comments:

The Economist's “Where the Smart Is: Connected Homes Will Take Longer to Materialize than Expected” from June 11th, 2016. While all sorts of “smart” devices are touted by utility executives and consultants, the reality is 72% of consumers have *no plan to* adopt smart-home technology. Further, only 15% of consumers will adopt said technology by 2021. The article offers the anecdotal evidence that a “smart fridge” sells for a “cool” \$5000. One would have to speak of incredible energy cost savings to remove this from the prohibitive section of most families’ budgets. (Footnote omitted.)

Utility Response to Consumer Perspective

Ameren Missouri, in its Reply Comments, responds the RRA ranking put forth by MIEC is based on the regulatory environment for all Missouri utility types – electric, gas and water, and notes benefits applicable to gas and water utilities not available to electric utilities. Ameren Missouri provides the following July 2016 comments from RRA:

In addition, RRA is maintaining its Average/2 ranking of the Missouri jurisdiction at this time, but is mindful of the fact that the 2016 legislative session concluded without action being taken on a bill that would have altered the state's ratemaking framework to address "regulatory lag." The issue is of particular concern to Missouri's electric utilities, and the matter is now being considered both by an interim legislative committee and the PSC. Although the utilities are generally supportive of potential changes to the regulatory paradigm, recent comments from the public counsel were dismissive of

regulatory lag concerns. *Should the legislature or PSC fail to take action to address these concerns, a reduction in the ranking may be justified.* (emphasis added by Ameren Missouri).

Other Stakeholder Perspective

The Division of Energy (“DE”), in its comments states, “rate of return regulation also has limitations in providing full and timely cost recovery of large investments in new technologies, creating a significant barrier to modernization and diversification of grid resources.” DE goes on to say “[The Missouri Energy Efficiency Investment Act (“MEEIA”)] provides a targeted mechanism to encourage the development of beneficial demand-side resources on the customer side of the electric meter, but does not adequately facilitate accelerated investment in the utility-owned infrastructure required to fully leverage demand-side opportunities.”

IBEW Local 1439 submitted comments suggesting capital spending should not be the main focus of utility spending, stating that under the current process, “it is much easier to recover capital expenditures than O&M. As a result, the electric utility companies are recharacterizing O&M as capital, or when they cannot, minimizing O&M and opting for new equipment.”

Earth Island Institute d/b/a Renew Missouri (“Renew Missouri”) suggests the current cost of service ratemaking system (“COSR”) does not “adequately [] respond to the will of Missourians in the modern day energy sector for a variety of reasons.” Renew Missouri states that COSR is predicated on two assumptions: 1) utility sales will continue to increase; and 2) from the perspective of the consumer, there is no qualitative difference in energy generation as long as standards of safety, reliability and affordability are maintained. Renew Missouri states that “changes in the modern energy world have shown both assumptions...are in fact false.” Renew Missouri indicates that when viewed as a supply-side resource, energy efficiency is the most cost-effective resource and renewables, such as distributed solar generation, is financially

attractive to end users; yet, according to Renew Missouri, IOUs fail to embrace these technologies because they pose a threat to utilities in the form of lost revenues.

B. Regulatory Lag

Utility Perspective

Missouri Energy Development Association (“MEDA”) comments,

Significant regulatory lag creates a powerful financial incentive for utilities to limit their investment in their systems to the bare minimum necessary to provide safe and adequate service...Taking so long to reflect cost changes in rates is neither good for the regulated utilities nor the customers they serve. When costs are escalating, the delay simply decreases cash flows, increases financing costs, erodes earnings on investments that are necessary to provide utility service, and diminishes the level of resources available to provide safe and reliable utility service.

Ameren Missouri, in its comments states,

Electric utilities are permitted to accrue an Allowance for Funds Used During Construction (AFUDC), which compensates them for their investment during the period that a capital item is being constructed. But once construction is complete and the capital item is placed “in-service,” all compensation for the cost of the capital ceases until the next rate case is completed and the item can be reflected in rates, often years later. Even worse, upon being placed “in-service,” capital items immediately begin to depreciate, generating depreciation expense not reflected in the utility’s rates and that reduces the utility’s earnings dollar-for-dollar. Consequently, the electric utility is not compensated for the cost of this depreciation between rate cases, and ultimately only the depreciated portion of the cost of the capital item is included in rates. In effect, customers receive a new capital asset but they only pay the cost of a used capital asset. Again, this under-recovery of cost is never made up.

Consumer Perspective

OPC comments,

Regulatory lag is perhaps the most necessary component involving cost of service regulation. Not only does this concept serve as a useful purpose in regulating and rewarding these IOU’s, but also that the time period has given the OPC, as well as other stakeholders, an opportunity to closely scrutinize data and evidence provided in the course of rates cases that, in turn, have saved Missouri ratepayers tens of millions of dollars a year.

OPC appears to acknowledge that excessive lag can discourage needed investments and increase administrative costs, but cautions that any mechanism designed to reduce regulatory lag should also allow for refunds in the event the utility collects more than their just and reasonable rates. OPC states that 23 states allow refunds of revenues for mechanisms such as shortened rate case timelines, interim rates, or rate adjustment mechanisms. Specifically, OPC makes the following points on regulatory lag:

Regulatory lag is not, in and of itself, inherently bad for the utility. The Commission recognizes that there are shared benefits, as well as risks, that run to both shareholders and ratepayers. Regulatory lag can serve to make the utility more efficient and more prudent, as well as provide the utility with retained benefits from synergies. Regulatory lag is a phenomenon which naturally occurs in ratemaking because the regulatory ratemaking process lags behind the actual costs and revenues incurred by the utility. *See* James C. Bonbright *et al.*, “Principles of Public Utility Rates”, 96 (2nd ed. 1988). When a utility is under-recovering revenues, regulatory lag can be seen as deleterious to the utility. *Noranda Alum., Inc., et al., v. Union Elec. Co. d/b/a Ameren Mo.*, 2014 Mo. P.S.C. Lexis 882, *29-30 (2014). When a utility is over-recovering revenues, regulatory lag can be seen as deleterious to the customer. *Id.* Traditional regulatory ratemaking is predicated on the idea that over a sufficient period of time the benefits and detriments of regulatory lag balance for both the utility and the consumer; sometimes a utility will over-recover, sometimes it will under-recover. *See* Alfred E. Kahn, “Economics of Regulation: Principles and Institutions”, 48 (1989). In effect, regulatory lag creates the “quasi-competitive environment” that mimics how competitive firms operate and ensures that natural monopolies are not abusing their power. (Footnotes omitted.)

Finally, OPC emphasizes that “even if the IOU’s are potentially exposed to some short-term risk that their expenses grow faster than normal, they are ultimately in control of when they file for rate increase. In contrast, ratepayers have no such defense.”

MIEC, in its Reply Comments states,

OPC is correct when it observes at page 8 of its comments that utilities benefit from certain offsets to this claimed loss of return on capital additions. These offsets include the effects of additional depreciation taken since rates were set, which reduces rate base, and additional deferred income taxes, which operate as a

deduction from new investments with the result that \$100 of additional capital spending does not produce a \$100 increase in rate base.

As an example of the offsets that exist, consider the circumstance of Ameren Missouri as recently revealed in its rate case filing in Docket No. ER-2016-0179. From the last day of the true-up period in its previous rate case (Docket No. ER-2014-0258) to the proposed last day of the true-up period in the current case, Ameren Missouri's capital additions totaled \$1.4 billion. However, the reduction in rate base that occurred from an increase in the accumulated reserve for depreciation (because of depreciation expense) and the benefit of accelerated tax depreciation, caused the actual increase in rate base to be only \$220 million. Thus, approximately 85% of the rate base impact (return on rate base) was offset.

A similar analysis for Kansas City Power & Light Company ("KCPL") between its previous rate case (Docket No. ER-2012-0174) and its current rate case (Docket No. ER-2016- 0285) indicates an increase in gross plant in service of \$200 million, but a decrease in rate base of \$4 million. Despite the increase in plant in service, the rate base went down, which means that KCPL did not require as much income to maintain the allowed rate of return on its rate base, producing regulatory lag that benefitted it.

MIEC, in its Comments Supporting and Responding makes the following observations:

The utilities frequently claim that regulatory lag discourages them from making appropriate infrastructure investments. Sometimes they imply that because of regulatory lag they will "lose money" on such investments. That is simply not the case. For example, even allowing for a whole year of regulatory lag, Ameren Missouri can expect to earn a profit (earnings on investment) of over \$90 million on a \$50 million equity investment (\$100 million total investment) in plant having a life of 40 years (assuming current ROE, debt equity ratio, and cost of borrowing). In other words, a \$50 million equity investment today yields a nominal profit stream of over \$90 million over the course of 40 years. This example demonstrates the compelling incentive provided to the utilities for capital spending -- Ameren Missouri makes no profit if it makes no investment.

MIEC continued later in its Comments Supporting and Responding:

A review of Ameren Missouri's Statement of Cash Flows filed with the Securities and Exchange Commission in Form 10-K reports show that "Net cash provided by operating activities" in 2015, 2014, and 2013 was \$1.2 billion, \$1.0 billion and \$1.1 billion, respectively. This internally generated cash flow can be used to pay dividends to Ameren Corporation and its shareholders, but is also available as an internal source of capital for construction. Internally generated cash can be reinvested each year before Ameren Missouri is required to access any new capital in the financial markets. Indeed, Ameren Missouri's recent levels of Capital Expenditures of about \$700 million per

year were mostly funded internally, by recovery from ratepayers' of depreciation and amortization of the Company's *existing* rate base assets as well as the income tax deferrals arising from bonus depreciation on such new capital investment. These internal funding sources annually contribute more than \$600 million per year that *must* be reinvested, in order to prevent Ameren Missouri from experiencing declining rate base and revenue requirements. (Footnote omitted.)

KCP&L/GMO's long-term growth outlook targets growth in rate base by at least 2 to 3 percent from 2016 through 2020 citing "targeted investments to empower customers and optimize our grid." At the same time, KCP&L/GMO targets annualized earnings per share growth of 4 to 5 percent "driven by investments in regulated utility infrastructure, disciplined cost management and national transmission opportunities," and dividend growth of 5 to 7 percent during the period 2016 through 2020.⁷ Ameren states to investors that its goal is to earn at or close to its allowed ROE in all jurisdictions, including Missouri, and also specifically states that it expects Ameren Missouri to earn within 50 basis points of its allowed Missouri ROE of 9.53 percent. Ameren estimates that its Missouri operations and maintenance expenses "not subject to riders or tracking mechanisms" will decline. Ameren states that it will continue to make prudent investments to provide safe and adequate service. Ameren's guidance to investors is for Missouri rate base growth of 2 percent annually from 2016 through 2020, and that its expected rate base growth and earnings growth is not dependent on any change in the regulatory framework in Missouri. (Footnote omitted.)

OPC and MIEC offer the following questions that should be asked of the IOUs as the

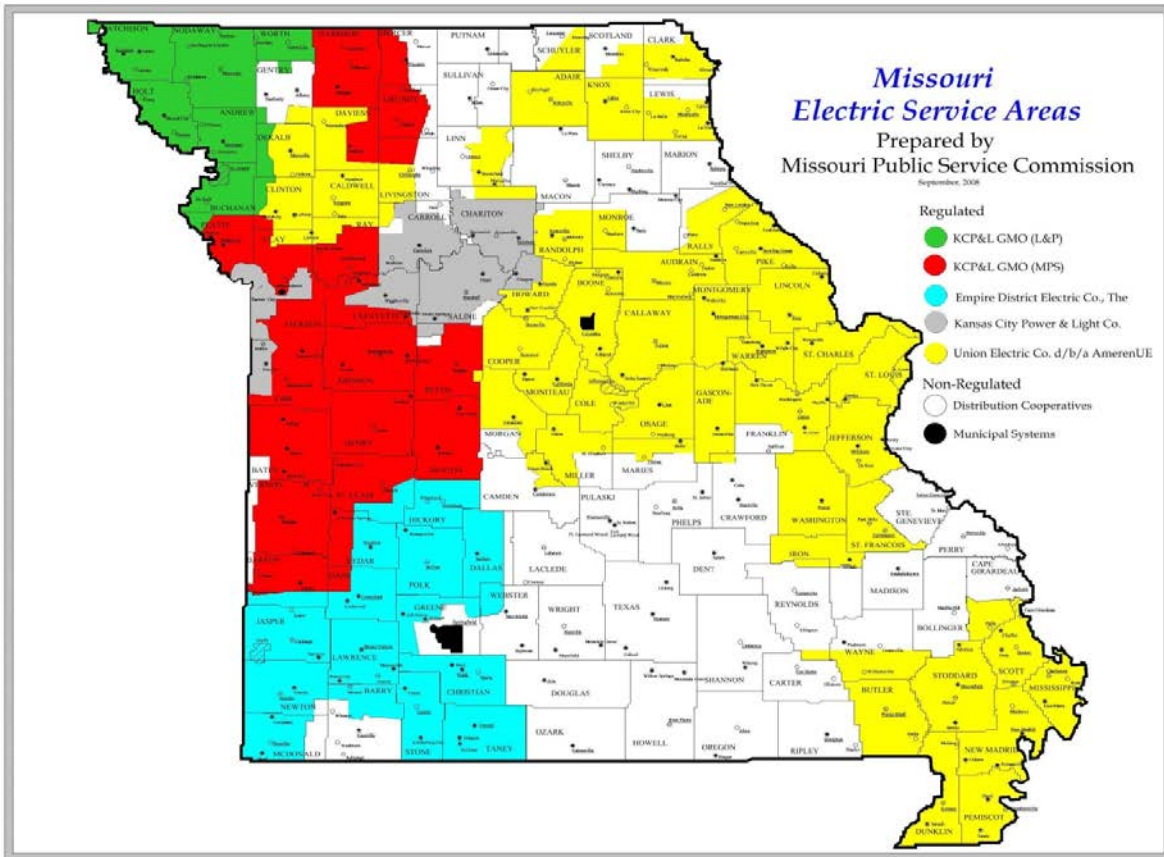
Commission considers the need for regulatory reform:

1. Provide a listing of all capital projects that have been abandoned due to regulatory lag.
2. Provide the source of information upon which you rely to show that regulatory lag impacts your ROE.
3. Please explain why regulatory lag cannot be reduced within the current statutory framework that governs the Commission.
4. Would you support changes in the Commission rules requiring mandated data requests be provided at the time a rate change application is filed?
5. Would you support changes in the Commission rules requiring shortened discovery response periods to expedite the review process?
6. Would you support changes to the Commission's rules on requiring travel to view highly confidential and proprietary information?

7. Provide your comprehensive long-range investment plan detailing the categories of investments that should be made. Provide economic and reliability-based justifications for the plan and project annual investment amounts by category.

Public Comments

Currently the Commission’s Electronic Filing System (EFIS) has recorded seventy-nine public comments. Most of the comments support a change to the regulatory process. Ten of the comments were from members of Missouri cooperatives and three of the comments were from Missouri municipal customers. Approximately 15 percent of the comments are utility customers largely not affected by the regulation of the Commission. A map of Missouri showing the portions of the State served by utilities predominately not regulated by the Commission will illustrate that large portions of the State will remain unaffected by regulatory reform.



SCHEDULE 2

Comments related to grid enhancements were conflicted as a portion wanted the grid enhanced regardless of the source of the energy while some commenters wanted system changes to promote renewable energy and eliminate coal generation.

The number of public comments received would approximate the number of public comments received in a utility's rate increase case. Empire's most recently completed rate case generated 103 public comments. Ameren Missouri's prior rate case generated 1,197 public comments. KCP&L's prior rate case generated 128 public comments. Finally, GMO's most recent rate case generated 28 public comments. These public comments are generally of the nature of opposition to an electric rate increase.

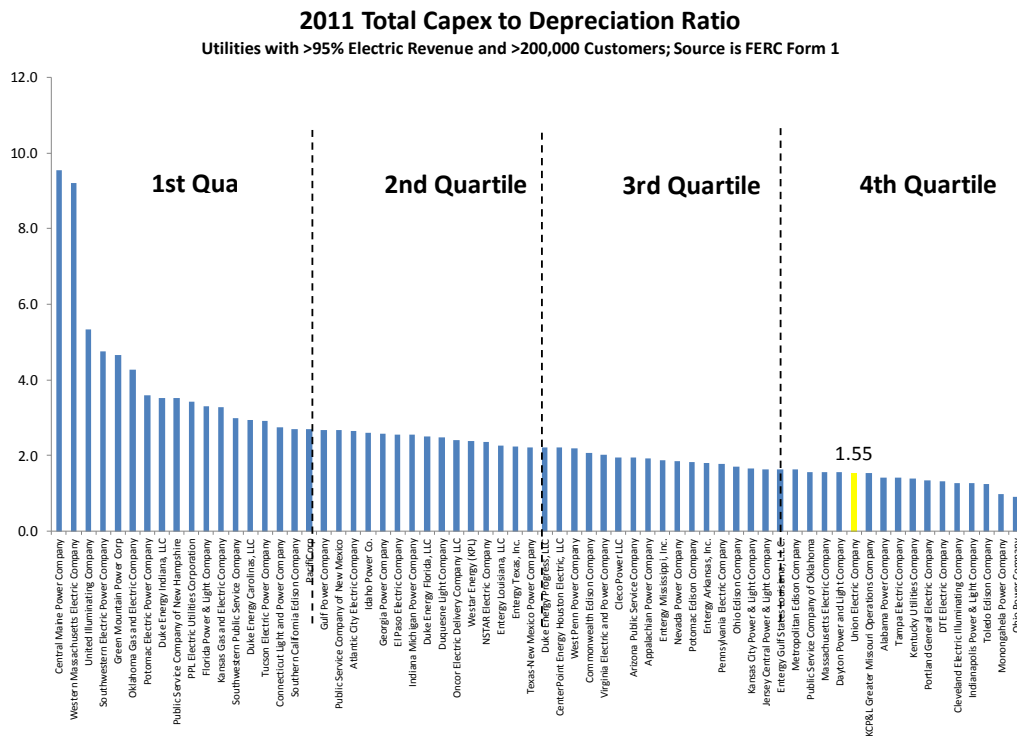
Public comments show that the issue of regulatory change differs regarding the nature of the change desired and extends beyond the Commission's jurisdiction; while, all options should be considered in the light of the need to implement rate increases to effectuate these changes.

C. Staff Response – Is there a problem that needs to be addressed?

While Staff is not convinced a problem exists to the level raised by the utilities, the myriad of comments suggest some degree of policy or legislative reform could be beneficial to the Missouri regulatory process. Much of the concern raised by the utilities is related to whether they will earn their authorized ROE when investing in infrastructure to meet customers' needs and expectations, including such things as renewable energy, DER and "self-healing" facilities to quickly restore service after an outage without human intervention. Further, regulatory lag is identified as a "disincentive" to investment.

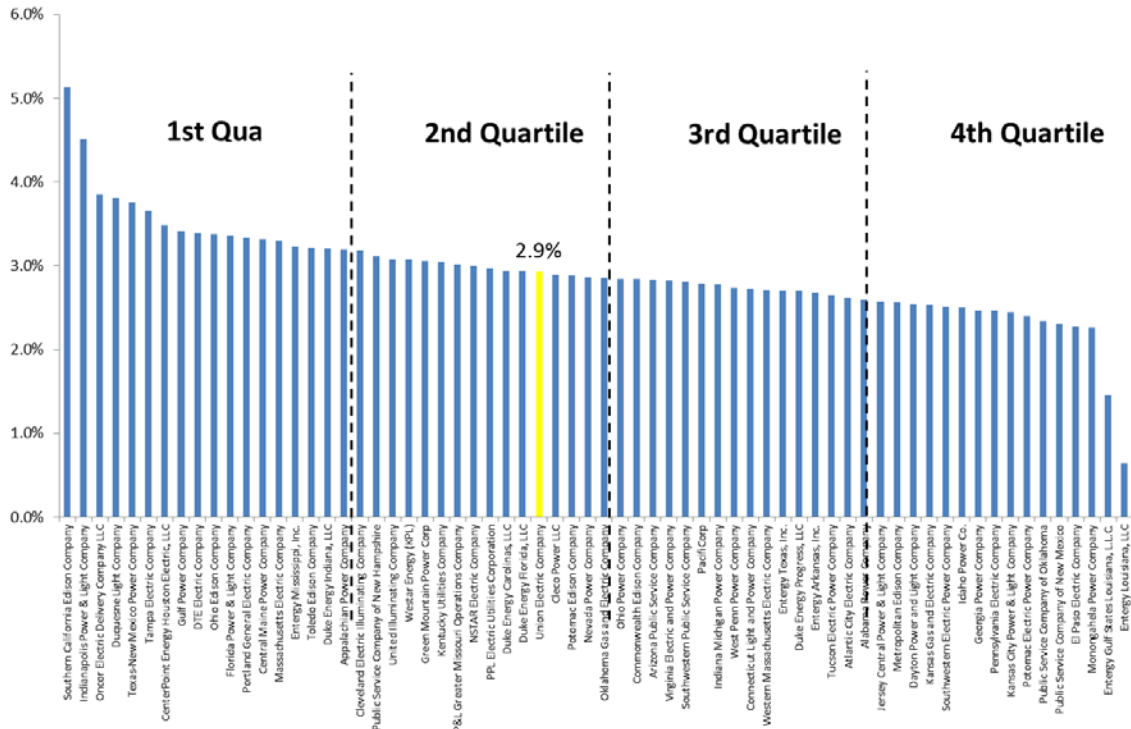
To gain a better understanding of utility regulatory concerns and investment needs, Staff met with Ameren Missouri on several occasions, including a field trip to meet with Ameren Illinois employees on technologies such as a "smarter" grid and advanced metering infrastructure

(“AMI”) deployment. These meetings not only allowed Staff to gain additional information, but also provided Ameren Missouri with insight into Staff’s perspective. For instance, when reviewing depreciation versus investment arguments, it was demonstrated that Ameren Missouri’s capital investment to depreciation ratio varies somewhat from year to year (1.55 in 2011 as demonstrated below to 1.37 in 2015), but Ameren Missouri is in the bottom quartile when compared to like utilities nationwide for all the years.



However, when comparing among the same utilities the ratio of depreciation expense to gross plant in service, Ameren Missouri’s depreciation expense is above mid-point when compared to other utilities. Because Ameren Missouri receives more than average depreciation expense, the same level of current Capex as an “average” utility would necessarily put Ameren Missouri at below-average ratio of Capex to depreciation. This demonstrates the varying perspectives and interpretations on the need for change to the current regulatory environment.

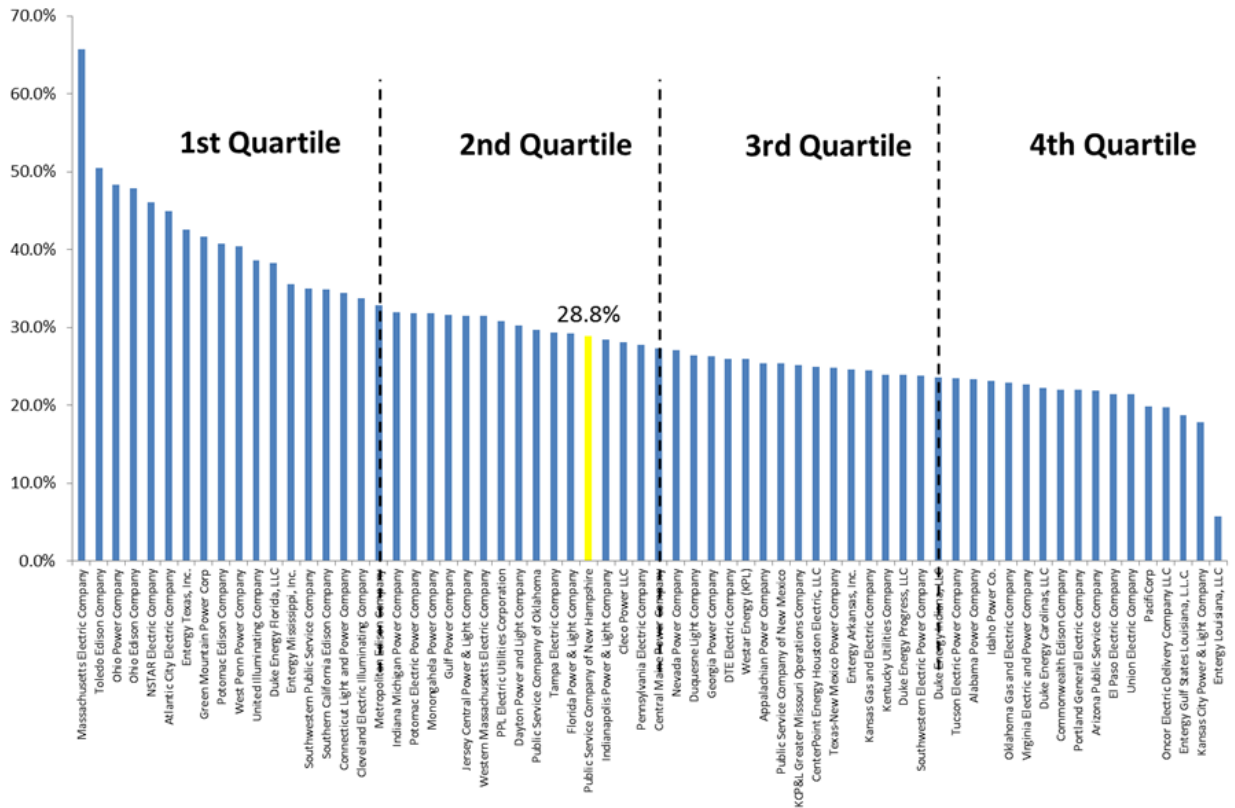
2015 Depreciation to Gross Plant in Service Ratio
 Utilities with >95% Electric Revenue and >200,000 Customers; Source is FERC Form 1



When comparing electric operating revenues to gross plant in service, Ameren Missouri’s revenues as a percent of gross investment is above-average, when compared to other utilities. This indicates that Ameren Missouri’s gross revenues as a percent of gross investment exceed those of the “average” utility.

2015 Electric Operating Revenues to Gross Plant in Service Ratio

Utilities with >95% Electric Revenue and >200,000 Customers; Source is FERC Form 1



Similarly, through discussions with Ameren Missouri, it became clear that any analysis on the need for or benefit of regulatory reform must not only include an analysis of investment costs and consumer benefits, but must also include an off-set for things such as reduction in costs due to automated processes or efficiencies gained from new technologies. For instance, during the meeting with Ameren Illinois it was presented that AMI will allow Ameren Illinois to provide same day service, remotely disconnect/reconnect customers, allow Contact Center Representatives to “ping” a meter while on the phone with a customer to potentially resolve issues, and implement outage filtering and analytics. All of these automated processes will reduce the need to send a service technician to site, and should ultimately result in cost reductions that will need to be considered when determining the value of the investment and the cost to the customer. Similarly, the reduction in outage duration possible through circuit

switching not only decreases labor costs during the restoration process, it also allows the utility to continue making sales to customers who would otherwise be experiencing an outage. It should be noted that the Illinois Commerce Commission (“ICC”) approves Ameren Illinois’ infrastructure investment plan. It should also be noted that Illinois legislation required metrics such as:

- Ameren Illinois deploy AMI to 62 percent of its customers replacing manually-read conventional meters
- A 56 percent reduction in estimated reads
- A 56 percent reduction in consumption on inactive meters
- A \$3.5 million reduction in uncollectible debt

Ameren Illinois estimates it will spend 4 times more than required by legislation due to the favorable regulatory treatment and will increase reliability by 20 percent due to automation. However, as demonstrated through discussions with Ameren Missouri and Ameren Illinois, Illinois has a different infrastructure configuration than Missouri and had reliability and safety issues that are not present in Missouri that needed to be addressed. Specific to customer meters, it is interesting to compare Missouri’s current environment to that of Ameren Illinois. As the following table demonstrates using 2015 data, Missouri investor-owned utilities, under the current regulatory scheme have deployed automated meters, and with the exception of GMO, have far fewer “conventional” meters than Ameren Illinois with its grid modernization efforts.

Utility Name	# AMR	# AMI	# conventional	Total
Ameren Missouri	1,196,283	0	13,792	1,210,075
Ameren Illinois	664,150	249,548	309,624	1,223,322
KCP&L	1,784	273,109	11,174	286,067
GMO	456	14,032	299,501	313,989

Staff Response to Regulatory Lag Discussions

As is clear from the comments and discussion at the workshop, there is a wide variety of views on regulatory lag. Some stakeholders state that regulatory lag is “good” because it provides incentives for utility efficiency, allows time for thorough audit of utility costs, and ensures all costs are subject to review before being charged to customers in rates. Other stakeholders state that regulatory lag is “bad” because it impairs the financial health of utilities, may cause an increase in borrowing costs, and may forestall capital investment that would be in the public interest. In Staff’s opinion, both viewpoints are correct, but under different conditions.

What is “Regulatory Lag?” As with many terms, regulatory lag can have various meanings. One such definition of regulatory lag is the amount of time elapsed between when a utility’s cost of service changes and/or rates go into effect and the point in time when the utility’s rates will be changed. Another definition is the amount of time between when a utility’s capital expenditures are deemed to be “in-service” and when those expenditures are included in the utility’s rate base. Still another meaning is when the utility’s actual rate of return differs from its Commission authorized rate of return.

Regulatory lag exists in Missouri due to the manner in which investor-owned utilities are rate regulated. Missouri utilities are regulated on the premise of cost of service, or rate of return regulation. This practice means that utility plant must be in-service (i.e. used and useful or providing service to customers) prior to inclusion in utility rates. It also means that rates are based on a historical test year on a going forward basis.

Unless statutorily required to file a rate case to continue an interim recovery mechanism such as the FAC or the ISRS, which are two examples of legislative changes to address regulatory lag, the utilities in Missouri elect when to file a rate case with the Commission. For

many years, electric utilities in Missouri did not request rate increases and presumably benefitted from regulatory lag. In recent years, electric rate cases have been filed, on average, every 18 to 24 months and regulatory lag has been raised as a concern.

The theory of regulation is an economic theory that needs legal force to implement and accounting practice to operate. Industries that currently fall under the need for rate regulation are those that generally are considered to be natural monopolies. A natural monopoly is a firm that exhibits declining average costs as output increases. This means that it is economically more efficient for one firm to provide the service than to have multiple firms competing. Within these industries, the products they provide (electricity, water, sewer, natural gas) are considered essential commodities. In other words, consumers have to have the product provided to function in today's modern economy. Since monopolists have the ability to set their own price to the captive customer, these firms were long ago placed under rate regulatory authority. In exchange for having its rates regulated, the utility was given an exclusive service territory in which to operate without fear of competition. This concept is commonly referred to as the "regulatory compact."

Under the regulatory compact, the utility has an obligation to invest in and build the necessary infrastructure to provide service to the customers in its service territory and the utility's regulators are obligated to provide the utility with an opportunity to earn a reasonable rate of return on that investment. In addition, the regulator must make decisions that are in the public interest, that ensure the utility is providing safe and adequate service, and that the utility is charging rates to customers that are just and reasonable. In non-monopoly markets, market forces make those decisions for the company and the consumer. Under the regulatory compact, the regulator is to act as the surrogate for competition.

Regulatory lag provides an incentive for the utility to be as efficient as possible. In competitive environments, it is competition and the market that provide this incentive. Since utilities live in a market free from competition, an outside force needs to be present to place the benefits of competition on the firm. If the firm can operate more efficiently, those cost savings are allowed to be realized by the utility and kept as additional earnings. Conversely, regulatory lag ensures that a utility will experience lower earnings when its costs increase if it is not operating in a more efficient manner.

Specifically, if the utility reduces its costs after new rates go into effect, the utility and its shareholders retain those savings. If costs rise after new rates go into effect, the utility and its shareholders will absorb those costs unless they file for rates to address those costs in a timely manner. Presumably the utilities are, by and large, in the position to plan for large cost expenditures and the timing of their general rate cases.

Missouri has an eleven-month operation-of-law period, but utilities typically do not face a full eleven months of regulatory lag. Utilities can “time” their rate case filings to cover events that will occur in the near future (plant additions, payroll increases). “True-up” update processes within rate cases mean that rate cases can take into account material cost drivers that occur up to approximately five months prior to when rates take effect. In most recent rate cases, the majority of the rate increase request applies to costs that have not been incurred at the time the rate application is filed.

Consider the following hypothetical rate case example:

Assume that a utility believes it will require a rate increase. That utility might choose to file a rate case as of January 1, 2017, based upon a test year of the historical costs it incurred in the twelve months ending September 30, 2016.

After the case is filed, Staff will conduct a thorough audit of the utility’s rate request. As part of its audit, it will review actual financial results from the utility’s test year, but it will also review actual financial results for the test year update period through March 2017. Accordingly, when the Staff files its initial recommendation as to an appropriate rate increase amount around mid-year 2017, that recommendation will take into account actual audited utility financial information through the end of March 2017.

However, a true-up audit will later be conducted to take into account financial changes occurring from April through June 2017. When the Staff’s true-up revenue requirement recommendation is filed in the late summer or early Fall of 2017, that recommendation will be based upon actual audited utility financial data through the end of June 2017.

In other words,

Rate case filed	January 1, 2017
Historical costs based on test year ended	September 30, 2016
Update period	October 2016 through March 2017
True-up period	April to June 2017
Rates effective	November 2017

In this hypothetical, the rate relief ultimately ordered by the Commission for the utility in November 2017 (assuming a full eleven-month rate case process) will reflect audited and verified utility financial results through the end of June, 2017, or a “lag” of approximately 5 months.¹¹

Much of the utilities’ recent emphasis in discussing the detrimental impact of regulatory lag has concerned the impact of new plant additions on earnings. Some of the utilities’ statements in their comments filed in this case and in the September 13, 2016 workshop seemingly imply that utility earnings must necessarily decline every time they place a plant asset

¹¹ The Commission has the authority to reflect in customer rates changes in costs in rates that occur after the true-up cut-off date but before the effective date of new rates. One type of cost commonly afforded such treatment is contractual bargaining unit salary increases.

in service, as the companies fail to either earn a return on the asset or to recover depreciation expense calculated on the asset balance until such time when new rates go into effect as a result of a later rate filing. However, this implication is simply incorrect. Whether a utility's earnings results are adequate at any point is dependent upon a myriad of factors, of which new plant additions are but one. Among other factors directly related to plant-in-service ratemaking, the required return on assets already included in utility rate base continually decreases over time, as depreciation expense is recovered in rates on those assets. Rate base is also being continually reduced through the collection of deferred taxes¹² by the utility in customer rates. Therefore, whether a utility suffers a negative earnings impact from plant additions is dependent upon whether the rate base increases associated with plant additions, in fact, outweigh the ongoing rate base reductions associated with growth in the utilities' accumulated depreciation reserve and accumulated deferred tax reserve balances. It should not be assumed that utility rate bases are constantly growing over time. Staff's review of the relevant financial information shows that most of Missouri's electric utilities have shown relatively little growth in rate base over the last five to six years. For this reason, Staff considers that Missouri electric utilities have not faced unusual earnings pressure as a result of their plant rate base additions in recent years.

Further, some major categories of costs are effectively subject to little or reduced levels of regulatory lag due to current use of single-issue rate mechanisms and "tracking" mechanisms in Missouri, such as fuel/purchased power expense, pensions/OPEBs benefits expenses, energy efficiency revenue and expense impacts, and renewable energy investment costs.

¹² "Deferred taxes" are amounts currently collected in rates by a utility for its federal and state income tax expenses that will not actually be paid to taxing authorities until a future period due to provisions in the Internal Revenue Service Code. Most utility deferred taxes are created as a result of allowing accelerated depreciation for tax purposes on new plant additions.

The reality of regulatory lag is that it provides regulated utilities with the same incentives to hold down their costs that competitive firms face from the discipline of the marketplace. The impact of reduced earnings associated with cost increases is a strong incentive for utilities to keep cost increases to a minimum, and the impact of increased earnings associated with cost decreases is a strong incentive for utilities to attempt to become more productive over time.

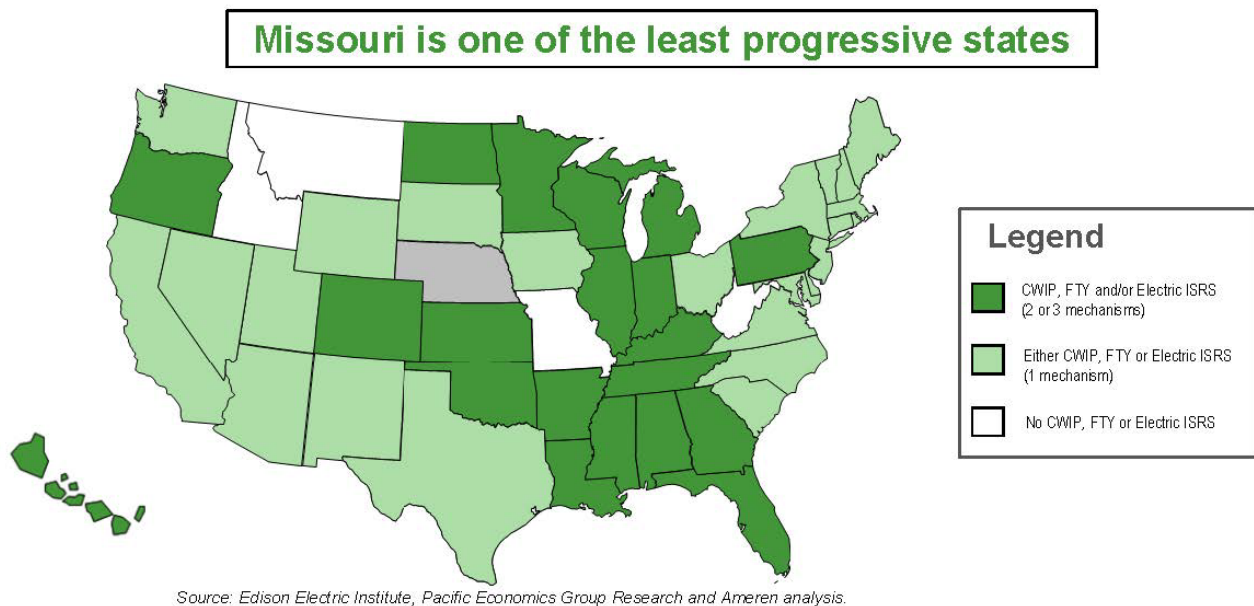
Due to its incentives, allowing for the potential for some amount of regulatory lag within a ratemaking structure is better than employing a ratemaking approach that seeks to eliminate regulatory lag in entirety or almost in entirety.

III. Other States' Regulatory Policy

Various comments identify state regulatory reform initiatives, including efforts in Arkansas, California, Georgia, Illinois, Indiana, Maryland, Massachusetts, Minnesota, and New York. In its September 23 response to Staff questions¹³, Ameren Missouri provides the following map as a state comparison of regulatory policies:

¹³ “The Critical Need to Replace Aging Electric Infrastructure and Build a Smarter and More Efficient Grid to Meet Customers’ Needs and Expectations”.

State Comparison of Electric Utility Mechanisms for Infrastructure Investments



As an additional resource, OPC provides an attachment and a matrix summarizing state regulatory practices.

Following is a high level summary of the other state initiatives as highlighted in this working docket.

i. Arkansas

A public utility filing an application for a general change or modification to its rates and charges under § 23-4-401 et seq., may file a notice with the Arkansas Public Service Commission (“APSC”) electing to have its rates regulated under a formula rate review mechanism. A formula rate review mechanism approved by the APSC shall specify the minimum information required with each annual rate review filing.

- Utility information for each annual filing to be filed 180 days prior to rate effective date.
 - Projected year or a historical test period of 12 months or 6 months of actual data and 6 months of projected data.

- If projected data is used, the revenue requirement is to be trued-up and netted in the next filing.
 - Disallowed costs are not eligible for recovery or relitigation in a formula rate filing.
 - The utility shall submit documentation fully supporting all calculations and adjustments as required by the rules of the commission.
 - Customer rates shall be adjusted in a formula rate review mechanism based on a comparison of the earned return rate to the target return rate.
 - 0.5 percent +/- dead band
 - The total amount of a revenue increase or decrease for each rate class shall not exceed 4 percent of each rate class' revenue for the twelve 12 calendar months preceding the formula rate review test period.
 - Formula Rate's term limited to an initial 5 years, but may be extended to 10 years.
 - Must continue as needed for any netting adjustments from prior projected data.
- Any party may file a statement of the errors or objections at least 90 days before the annual rate effective date.
- Utility files any corrections or rebuttal to the errors or objections at least 75 days before annual rate effective date.
- The APSC shall hold a hearing at least 50 days prior to effective date.
- The APSC shall issue a final order at least 20 days before effective date, or the utility may charge its proposed rates subject to refund. – If this happens the APSC may require posting of a security on the refunds and interest.
- § 23-4-422 amended so that” if the commission finds that it will be beneficial to economic development or the promotion of employment opportunities, and that will result in just and reasonable rates for all classes of customers,” the commission shall ensure that all demand and capacity related costs and expense are allocated and recovered from customers in those classes on a demand component, and provides specifics on how this will be accomplished.

ii. California

- In 2003, the California Public Utility Commission (“CPUC”) adopted a policy that all electric customers should have advanced meters.
- California was the first state to pass a statewide grid modernization policy.
- In September, 2009, the CPUC established an expedited review process for grid modernization funding.¹⁴

iii. Georgia

In its comments, and also during a presentation at the workshop, Liberty Utilities (“Liberty”) described the Georgia Rate Adjustment Mechanism (“GRAM”). GRAM was

¹⁴ DE comments.

approved by the Georgia Public Service Commission (GPSC) in 2011 for Atmos Energy's Georgia service territories. (Atmos Energy is a natural gas utility.) "GRAM provides for annual rate adjustments based on projected earnings during a future period, using a rate stabilization feature and an element of decoupling through a true-up mechanism."

- GRAM incorporates adjustment mechanisms, calculation methodologies and ratemaking allowances/disallowances from the utilities most recent rate case order.
- The annual GRAM filing includes a report on historic test year data and a projection of future test year data for:
 - Cost of operation
 - O&M is inflated for certain elements for the next forecasted period
 - Rate base
 - June 30 actual adjusted by capital budgets for the period
 - Cost of capital is forecasted using
 - ROE established in last rate case
 - Cost of debt and capital structure as of June 30 actual
 - Revenues forecasted based on number of customers and use-per-customer trends
- Rate adjustments are appropriate if the utility's earnings during the forward-looking test year are expected to be above or below an established rate of ROE
 - If earnings are projected to be within a dead band, no adjustments
 - If earnings are projected to be outside a dead band, new rates are adjusted
- Revenue true ups
 - Actual revenues are compared to projected revenues
 - A positive or negative revenue true up factor is applied
- Purchased gas adjustment ("PGA"), pipeline replacement program and weather normalization adjustment are not affected by GRAM

iv. Illinois

Under §16-108.5, a participating utility may elect to recover its delivery services costs through a performance-based formula rate approved by the ICC, with sufficient specificity included in the application to allow the performance-based formula to operate in a standardized manner and be updated annually with transparent information that reflects the utility's actual costs to be recovered during the applicable rate year.

- In the event that the average annual increase exceeds 2.5 percent, the utility is no longer eligible to annually update.
- The utility shall file tariff changes every 3 years, allowing the ICC an opportunity to consider revenue-neutral tariff changes related to rate design.

- Utility can voluntarily elect to participate in the infrastructure investment and modernization program.
 - If a participating utility is not satisfying its investment commitments then the utility shall no longer be eligible to annually update the performance-based formula rate tariff.
 - Combination utility investment levels
 - Over a 10-year period the utility needs to invest an estimated \$265 million in electric system upgrades and modernization projects.
 - \$245 million in infrastructure improvements, including undergrounding of residential distribution and mainline cable refurbishment and replacement.
 - Training facility construction or upgrade totaling 1 million, LEED certified.
 - Wood pole inspection, replacement and treatment
 - \$200 million for storm mitigation including undergrounding and reengineering of circuits
 - Over 10 year period the utility needs to invest an estimated \$360 million in transmission and distribution infrastructure and Smart Grid electric system upgrades
 - Advanced metering plan and requirements
- Job creation - 450 jobs should be created when the “peak” of plant investment takes place
- Utilities need to meet certain service quality measures. They will receive ROE adders or subtractions based on meeting the metrics.

v. Indiana

Ameren Missouri, in its Reply Comments, explains the Indiana Utility Regulatory Commission (“IURC”), in an effort to offer faster recovery of capital investment, approved a plan that allows Duke Energy to invest \$1.4 billion in infrastructure improvements through 2022, recover the costs through a rider, and earn an allow ROE of 10 percent.

vi. Maryland

- Between 2010 and 2013, the Maryland Public Service Commission (“MdPSC”) approved utility installation of AMI as part of grid modernization efforts.
- Utilities were required to develop customer education programs and cyber security plans associated with the AMI deployment.¹⁵

¹⁵ DE comments

vii. Massachusetts

- In 2014, the Massachusetts Department of Public Utilities (“MDPU”) issued the “Modernization of the Electric Grid” order requiring electric distribution companies to submit a ten-year grid modernization plan outlining planned efforts to:
 - Reduce the effects of outages
 - Optimize demand, while reducing system and customer costs
 - Integrate distributed resources; and,
 - Improve workforce and asset management
- The grid modernization plan must include infrastructure and performance metrics to measure progress.¹⁶

viii. Minnesota

DE gave a presentation at the workshop on the Minnesota MN e21 Initiative. The initiative was initiated/convened by the Great Plains Institute, and included a multi-track, multi-year process. The initiative address the relationship of policy goals to the utility model; universal access and customer preferences; rate design issues; the value of the grid and distributed energy resources (“DER”); and, administrative cost reductions. A Minnesota Department of Public Utilities (MnDPU) cited the following objectives: reduce outage effects; optimize demand; integrate DERs; improve workforce and asset management. The order proposed a 10-year modernization plan, but did not recommend regulatory models or cost recovery frameworks. Working group recommendations included:

- A multi-year performance-based framework
- Use of pilot programs
- Establishment of grid and DER services valuation methods
- Review and adjustment of time-varying rates
- Use of collaborative regulatory processes with due process protections
- Create consistent policies through generic proceedings
- Forward-looking stakeholder processes
- Transparent, forward-looking, integrated grid modernization and DER integration
- Reduce costs by improving grid utilization

¹⁶ DE comments

ix. New York

DE's presentation also included a summary of New York's Reforming the Energy Vision Initiative ("NY REV"). The goal of NY REV is to achieve a "...consumer-oriented market that encourages innovative, market-based solutions that reduce costs while meeting critical environmental needs". A summary of NY REV follows.

- Clean energy goals for 2030
 - 40 percent greenhouse gas ("GHG") reduction over 1990
 - 50 percent renewable energy generation
 - 23 percent building energy consumption decrease over 2012
- Innovation/realign utility model with policy goals
- New York Public Service Commission ("NY PSC") scorecard
 - Metrics for PBR and tracking policy goals
 - Reliability measurement
 - Earnings adjustment mechanism to incent peak reduction, system efficiency, energy efficiency, small system interconnection, customer engagement and information access, GHG reductions and affordability
 - New York has a rate of return adder on a demand management program that includes the following performance indicators: quantity of alternative measures (capacity of alternative measures installed), diversity of DER vendor marketplace and reduction in dollars over MegaWatt costs.
- Market Activation - New York State Energy Research & Development Authority ("NYSERDA") for market development, innovation and research, and targeted support to certain communities
- Leading by Example – New York Power Authority piloting technologies, providing expertise, showcasing grid innovation/upgrade opportunities, increasing state-owned building efficiency and distributed generation

OPC discusses a proposal released by the NY PSC staff which uses three tools to align utility shareholder value with six public policy goals: 1) earnings incentive mechanisms; 2) measuring, but not monetizing, performance metrics; and 3) reforming the "claw-back" mechanism such that capital expenditures are adjusted in each rate case. The new claw-back model would allow utilities to keep the difference between planned capital expenditures and third-party solutions. New York also adopted a 20 percent/40 percent fuel adjustment sharing

mechanism by which utilities would absorb fuel costs above its forecast, or the utility would retain savings if costs come in below the forecast.

Staff Response

Staff has the following general comments regarding the regulatory practices of other states in adopting the various ratemaking approaches that are under consideration in this docket:

First, there is no clear consensus among the state jurisdictions regarding any of these particular ratemaking approaches. Based upon Staff's review, none of the specific approaches advocated by the utilities are routinely used in a majority of the states.

Second, where these initiatives have been adopted, usually it has been on a more limited basis than the broad application often advocated for in the comments and in the workshop. As examples, when either ISRS-type plant rate recovery mechanisms or CWIP in rate base is allowed in other jurisdictions, the treatment is usually applicable only to defined subsets of plant investment (for example, transmission plant additions or environmental additions), and not for all plant additions. These limitations are particularly relevant where the contemplated investment is likely to either produce significant offsetting settings, or offsetting revenue. For example, if labor savings will result from grid automation, it would be inappropriate to include the increase to rate base, but exclude the reduction in labor costs caused by that automation.

Third, while the utilities have identified the historical cost basis for setting rates used in Missouri as the root cause of their alleged earnings difficulties, a distinct majority of the states use historical cost ratemaking as opposed to forecasted test year approaches. In fact, many state jurisdictions require that utility rate base be measured on an average historical test year basis, and not the end-of-true up period basis normally used in Missouri under the current ratemaking practice.

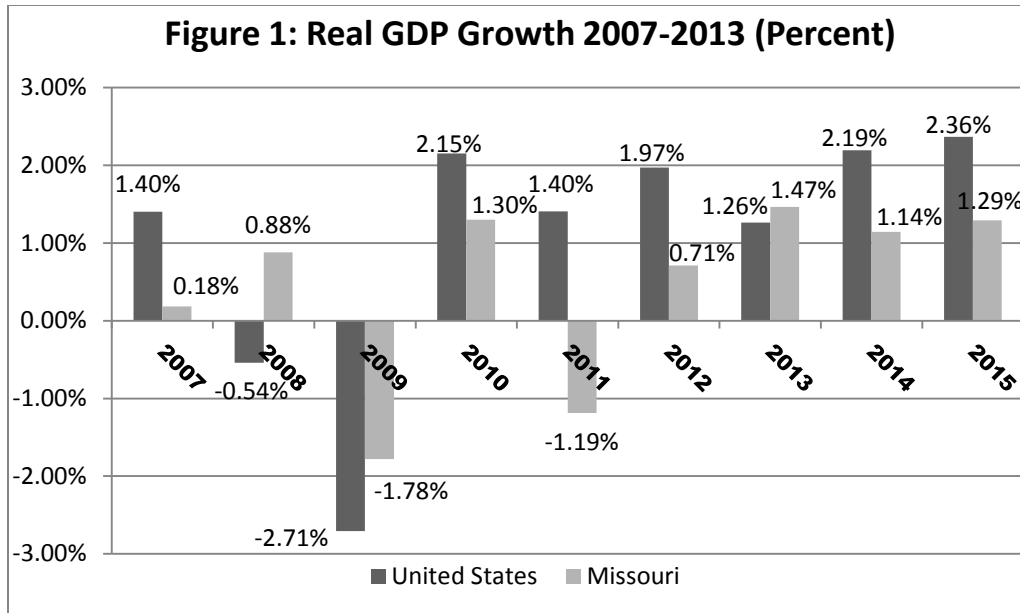
Finally, the form of formula ratemaking that provides for automatic upward and downward rate adjustments to allow the utility to earn at or near a “target” rate of return is currently used by only five states for electric utilities (Alabama, Arkansas, Illinois, Louisiana and Mississippi).¹⁷ The only states that have implemented this type of ratemaking in recent years are Arkansas and Illinois, with Arkansas using the rate case process to set the formulaic parameters, and Illinois including specific statutory conditions related to jobs and investments.¹⁸

Caution should be used when applying ratemaking methodologies that have been used in other states to Missouri just because, “they have been successful”. Missouri’s economic environment is not necessarily consistent with the economic environment of other states.

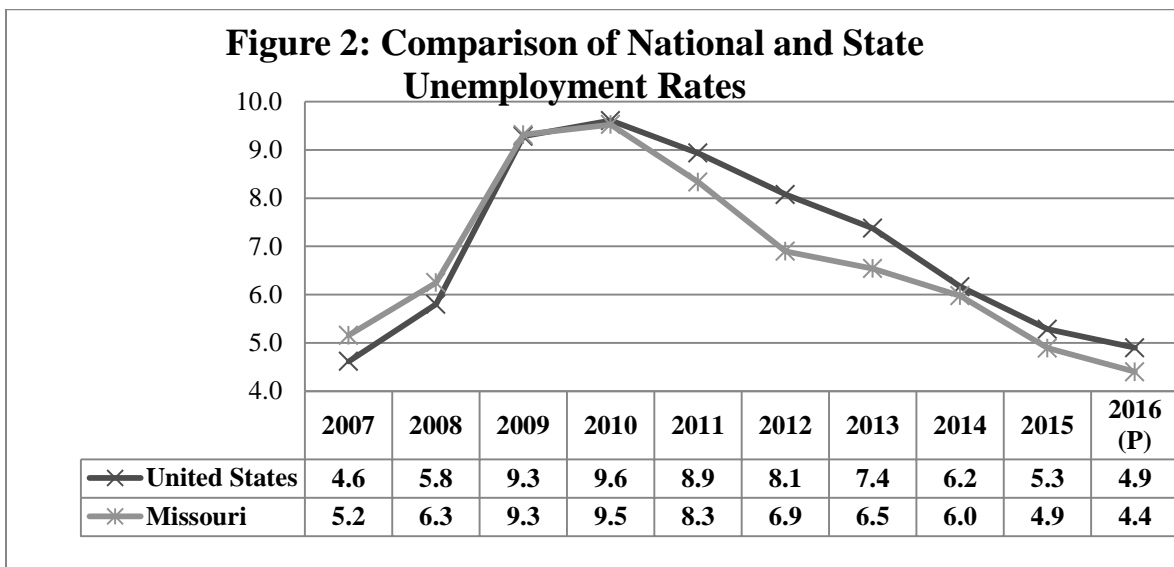
The indicators of Missouri’s general economic condition indicate that moderate growth continues. Figure 1 below shows that the real gross domestic product (“GDP”) growth of Missouri has averaged less than one percent (1 percent) per year from 2010 to 2015. Preliminary 2015 data had shown a robust year-over-year growth rate at 2.80 percent, but subsequent revisions lowered the growth to only 1.29 percent.

¹⁷ A larger number of states allow for “sharing” between utility customers and shareholders of actual earnings above the utility’s target return on equity, but do not allow for automatic rate adjustments if the utility earns below the target return on equity.

¹⁸ Staff relied on a number of sources for its analysis of other states, including review of state statutes and orders, outreach to other states and the SNL database.

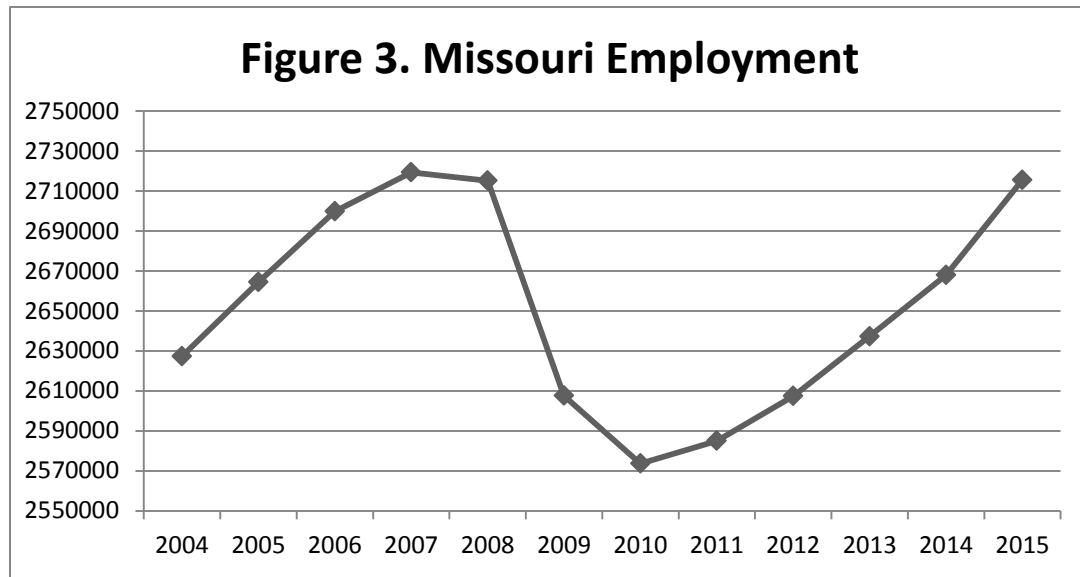


Despite a low GDP growth rate, Figure 2 shows that the annual unemployment levels for Missouri, including the preliminary 2016 levels, are below the pre-recession levels, but the unemployment rate for the U.S. rate has yet to reach the pre-recession lows.¹⁹



¹⁹ According to the National Bureau of Economic Research, the recession began in December 2007 and ended in June 2009.

Some economists have expressed concern that the unemployment rate statistic has not accurately reflected a lower labor-force participation rate. Figure 3 shows the number of employed persons in Missouri is near the pre-recession peak. While not correcting for population growth, Figures 2 and 3 together show that the employment situation in Missouri continues to improve.



In addition to examining the status of the current economy, economic forecasters also examine economic data that has a history of leading, lagging, or coinciding with changes in the broader economy to anticipate future economic conditions. The current economic outlook from a variety of economic forecasters has been less than optimistic. For instance, the American Institute for Economic Research’s (“AIER”) ²⁰ most recent version of Business Cycle Conditions (September 2016) shows that 42 percent of the leading indicators are evaluated as expanding. ²¹

²⁰ American Institute for Economic Research. (09JUN16). “Business Conditions Monthly.” <https://www.aier.org/bcmoverview2016june> (28JUN16).

²¹ AIER uses 24 indicators in total – 12 leading indicators are a measurable economic factor that tend to change ahead of a turning point in the broader economy, six coincident indicators that tend to change at roughly the same time as a change in the broader economy, and six lagging indicators that tend to change after a turning point in the broader economy. AIER recently revised its list of indicators, details of which can be found at <https://www.aier.org/revising>. A leading indicator evaluated as expanding means that the change in that indicator is historically correlated with future economic growth.

Under AIER’s method, consistent evaluations above 50 percent suggest a low probability of recession over the next six to 12 months. This marked the sixth month in a row that was at or below 50 percent. AIER states, “Normally, readings below 50 begin to raise warnings about an increased risk of recession. However, we believe the results over the past seven months are consistent with overall slow-growth.”²²

Figure 4 provides a comparison of the increase in average weekly wages for the counties in Missouri to the Consumer Price Index ("CPI") and the Producer Price Index ("PPI").²³ The overall Missouri increase in average yearly wages over the period analyzed was 18.5 percent, just above the increase in consumer prices over the same period.

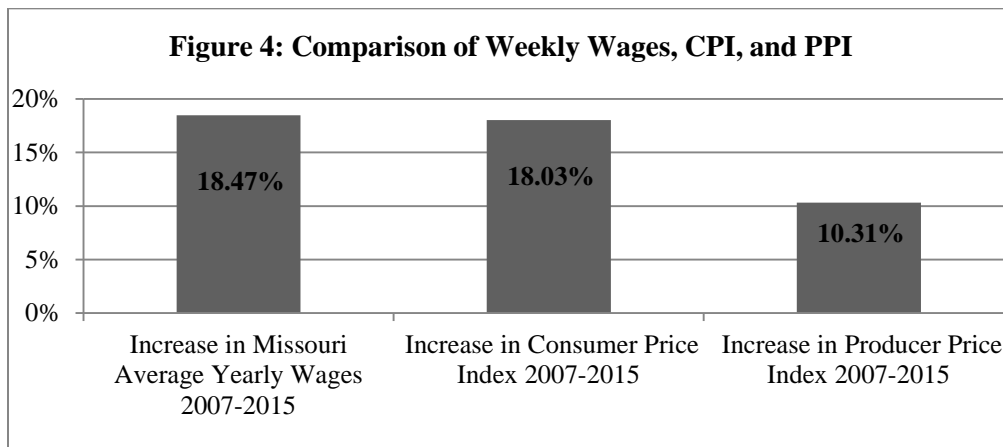
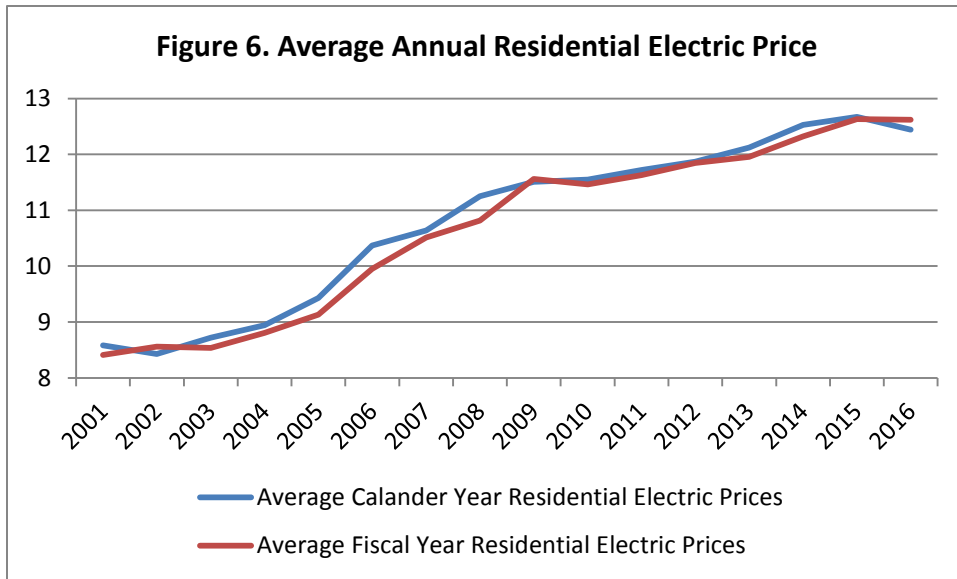
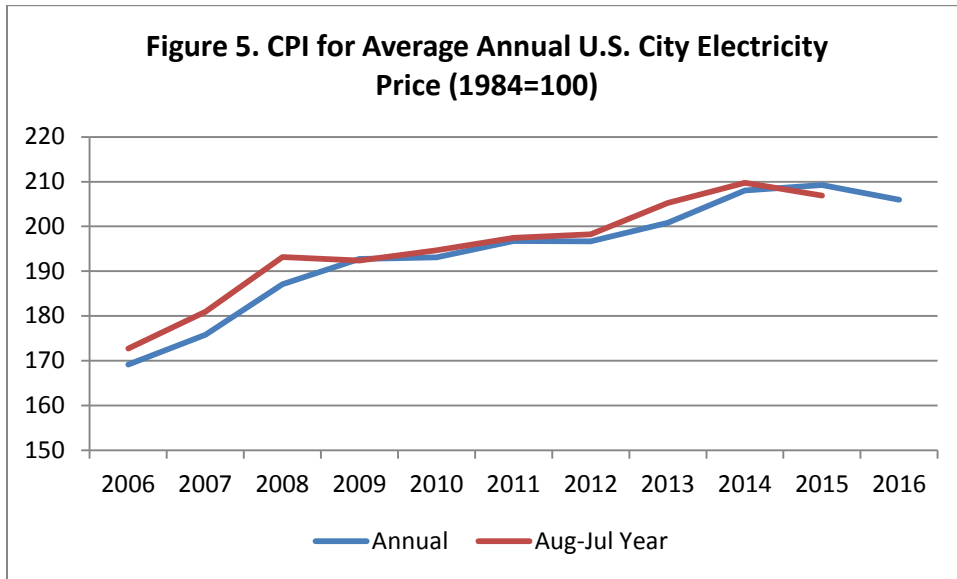


Figure 5 is a graph of the electrical component of the CPI published by the Bureau of Labor and Statistics, and Figure 6 is the average residential price of electricity published by the U.S. Energy Information Administration. As can be seen, the average expenditures on electricity (Figure 5) and average residential electric price (Figure 6) have dropped slightly over the last

²² American Institute for Economic Research. (14SEP16). “Business Conditions Monthly.” <https://www.aier.org/bcmeconomy2016september> (04OCT16).

²³ The PPI represents the Producer Price Index for Industrial Commodities which includes textile products and apparel, hides, skins, leather and related products, fuels and related products and power, chemicals and allied products, rubber and plastic products, lumber and wood products, pulp, paper and allied products, metals and metal products, machinery and equipment, furniture and household durables, nonmetallic mineral products and transportation equipment.

year. It remains to be seen whether these decreases are part of a new trend or a brief hiatus in a broadly increasing environment.



Finally, the American Society of Civil Engineers’ 2013 Report Card for Missouri’s Infrastructure states,

Missouri is unique in that it is a member of three power distribution networks. Approximately 81 percent of the energy in Missouri is produce[d] through coal power plants with another 12 percent being provided through nuclear energy; the remainder of Missouri’s energy needs are [met] through natural gas, hydroelectric and wind generation. Aging infrastructure and government regulation continue to

be major drivers for large expenditures at both the power plants and in the distribution system. Energy prices in Missouri are currently very affordable; however due to a projected \$107 billion dollar national shortfall in funding, additional costs will likely be passed along to the customers and drive up energy costs.

Performance Metrics

Whether considering current ratemaking practices, or considering modifications to the current regulatory environment, performance metrics is a key topic of discussion.

Brightergy suggests the integration of distributed and renewable resources be considered “pillars” of any performance metrics scheme.

DE suggests workforce asset utilization and cost-effective advanced metering deployment should be considered as performance measures.

With its comments, DE submitted “Utility Performance Incentive Mechanisms - A Handbook for Regulators” (“Handbook”)²⁴. The Handbook describes how regulators can guide utility performance through the use of performance incentive mechanisms, addressing performance incentive mechanisms that use financial rewards and penalties to encourage utilities to meet specific targets, as well as performance metrics for simply monitoring and reporting utility performance.

An overarching theme in the Handbook is that regulators have used performance incentive mechanisms for many years to address traditional performance such as reliability, safety, and energy efficiency. Performance incentive mechanisms under traditional cost-of-service regulation typically have been developed to improve service or reduce costs (for example, reliability, power plant performance, cost of renewable generation, or O&M costs). Some states have developed performance incentive mechanisms to support specific resource

²⁴ Prepared for the Western Interstate Energy Board. Melissa Whited, Tim Woolf, and Alice Napoleon. March 9, 2015.

goals, such as increasing renewable energy generation, energy efficiency savings, and resource diversity.²⁵ The Handbook cites Peter Bradford, Regulatory Incentives for Demand-Side Management, noting “All ratemaking is incentive ratemaking. It rewards some patterns of conduct and deters others.”²⁶

In a state with traditional cost-of-service regulation, performance metrics and incentives might be especially important to address areas with historically poor performance or areas where regulators see opportunities for greater efficiencies or reduced costs. Performance metrics and incentives should be designed to complement the existing regulatory incentives, such as incentives associated with capital investments, regulatory lag, increased sales, risk, and innovation.²⁷

According to the Handbook, performance incentive mechanisms may become more desirable as: 1) retail sales are increasing at much lower levels than in the past and in some cases declining; 2) utilities may be facing the need to replace infrastructure; and, 3) utilities may have more options to choose from in terms of generation, transmission and distribution technologies and more ways to address customer needs i.e. energy efficiency, demand response, distributed generation, automated metering technologies, and smart grid options.

The Handbook suggested key questions for regulators when considering performance metrics and incentives²⁸:

- How well does the existing regulatory framework support utility performance?
- How well does the existing regulatory framework support state energy goals?
- What are the policy options available to improve utility performance?
- Are industry, technology, customer, or market conditions expected to change?

²⁵ Handbook – page 12.

²⁶ Handbook - page 9.

²⁷ Handbook – page 16.

²⁸ Handbook - page 4.

- Does the Commission wish to articulate specific, desired performance outcomes? If so, in what performance areas?
- Does the Commission prefer to oversee utility expenses and investments after the fact (e.g., through rate cases and prudence reviews), or to guide performance outcomes before investments are made?

The Handbook offers these criteria for developing metrics:

- Tied to the policy goal
- Clearly defined
- Able to be quantified using reasonably available data
- Sufficiently objective and free from external influences
- Easily interpreted
- Easily verified²⁹

The Handbook also suggested dashboards for data reporting, contained in a website that is hosted by the utility or the commission, provide a useful forum for displaying performance information, ideally through both interactive graphs and downloadable data.³⁰

A key question posed in the Handbook is: “Will the set of new performance incentives be sufficient to modify, or at least balance against, the financial incentives of the existing regulatory model?” The Handbook recommends regulators compare the magnitude of the proposed performance incentives with the magnitude of existing financial incentives.³¹ The Handbook also recommended costs to customers of achieving the targets be balanced with benefits to those customers, suggesting ratepayer surveys can help to identify ratepayer priorities and how much they are willing to pay for higher levels of utility performance.³²

Other states have implemented performance metrics. For instance as part of NY REV, performance measures were implemented. In California, flawed data resulted in the loss of performance rewards and significant penalties. In 2013, during a re-examination of the revenue adjustment mechanism, Hawaii adopted 30 performance metrics to track utilities’ abilities to

²⁹ Handbook - page 28

³⁰ Handbook – page 32.

³¹ Handbook - pages 48-50.

³² Handbook- page 34.

achieve renewable energy goals, ensure reliability and reduce costs. The Hawaii Public Utilities Commission (“HPUC”) ordered that these metrics be posted on the companies’ websites. Proposals varied from traditional reliability and call center performance incentive mechanisms to mechanisms targeting reductions in fossil fuel use, and addressing the quality of utility resource planning.^{33 34}

The United Kingdom privatized energy distribution and transmission utilities in 1990 and a performance based regulatory framework was adopted with penalties or rewards in a variety of areas including: environmental, customer satisfaction, service connections, service interruptions, guaranteed standards of performance and health and load indices.³⁵

The Energy Policy Act of 2005, through the Federal Energy Regulatory Commission (“FERC”) developed incentive-based rate treatments for transmission investments. As part of FERC’s Order No. 679, transmission developers received higher rates of return on equity for new transmission investment in order to improve reliability and reduce congestion. According to the Handbook, the incentive, however, may have had an effect of increasing delivered energy costs. By applying the ROE adder to the projects actual costs, the Handbook states developers were given the incentive to increase the project costs (through, for example, delaying construction), because the higher ROE was applied to the total project cost.

Staff Response

As the Handbook notes, performance metrics are a standard practice in the current regulatory environment. Utilities currently provide performance reporting, including in the reliability and customer service area, to Staff. Some customer service reporting has been

³³ Handbook - pages 89-93.

³⁴ Staff reviewed the HPUC docket and found no Commission order regarding a conclusion of the second phase process of performance incentive mechanisms.

³⁵ Handbook - page 77.

obtained through individual utility cases and Staff monitors information such as reliability, call center, and meter reading data on a monthly basis from numerous utilities. When concerns arise, Staff's first action is to make direct contact with the utility.

Economic principles, including those that govern utility service, presently include incentive mechanisms since customers are willing to pay the utility for service, including enhancements, as long as the product is perceived to be worth the cost. Further, the utility is already receiving compensation, through its cost of service, for processes, practices, management, personnel, equipment and all other costs to achieve a given level of performance, so additional reward for performance could, in effect, be requiring ratepayers to "pay" twice. Utility companies are already incented, by virtue of guaranteed service territories and by cost of service regulation, to perform well.

If performance incentives are established as part of regulatory reform, a "baseline" of acceptable performance should be evaluated and documented. Caution should be taken such that a utility is not rewarded for performance that is unacceptable and/or sub-standard and caution should be given to not reward the utility for "what the utility should have been doing all along." The utility should not be incented to devote extra resources toward improving the particular reward-related indices at the expense of other important operational functions. Performance baselines should be utility-specific to reflect inherent operational differences such as determined by technology utilization, production mixes, management, customer bases, etc. Industry comparisons are not appropriate as many factors unique to the utilities themselves can and do influence performance including both factors within and outside utility control.

All efforts should be made to develop clear definitions of performance metrics and the reporting and monitoring of those metrics. Performance incentive mechanisms should be

designed to share financial benefits for superior performance between the utility and its customers. Conversely, penalties should be assigned exclusively to the utility since a penalty implies performance expectations were not met.

Requiring the utilities to maintain and report various performance metrics to the Commission places significant responsibility upon the Commission to develop a process to both receive and effectively monitor the metrics. Therefore, when devising performance metrics much thought must go into the receiving end of how the reports will be monitored. Consideration should also be given to verify and/or audit performance reporting.

IV. Possible Statutory/Policy Changes

A. Reform That Can Be Considered Under Commission's Current Authority

1. Additional Reporting Requirements

Stakeholders have suggested that increased reporting requirements, including enhanced minimum filing requirements, will reduce regulatory lag since the Commission, Staff and parties will have information prior to or at the time of a rate case filing.

2. Shortened Rate Case Processing

MECG suggests the Commission hold multiple meetings in a week to deliberate and decide rate cases.

OPC recommends non-utility parties file direct and rebuttal testimony at the same time. OPC also recommends a “two-step rate increase” that would recover expected post-order capital additions and identifiable expenses within a certain period of time. Finally, OPC recommends the Commission allow parties to a case to notice up motions for hearing as opposed to a regulatory law judge or the Commission setting this action. OPC suggests the Commission could

also create regulations establishing a set period of time for motions to be heard or establishing “a version of ‘Law Day’” where routine motions would be heard.

A possible limitation to the shortening of case timelines is the data lag of 2-6 months for utilities to provide monthly sales data. This data is necessary to determine the current level of a utility’s sales and revenues.

The Commission shortened the rate case process from 11 months to 10 months for GMO’s most recent rate case (Case No. ER-2016-0156).

3. True-Up Period

Stakeholders have suggested shortened response times during the true-up period.

4. Shortened Discovery Process

Stakeholders have suggested that shortened discovery response times will reduce regulatory lag. For instance, MECG requests that any regulatory change include a requirement for the utility to provide responses to standard data requests with the filing of the rate case, for more expansive minimum filing requirements and for a shortened response time for data requests.

MIEC recommends the Commission:

- Establish standard rate case filing requirements including specific data request items
- Shorten discovery response times to a more reasonable time
- Shorten the time between when the utility provides true-up data and when other parties respond

OPC also suggests regulatory lag could be reduced with modifications to the Commission’s discovery rules, and by incorporating a common set of DR questions into the 60-day notification period. OPC also recommends the requirement that parties view highly confidential or proprietary information at the utility’s office be eliminated absent a showing of substantial risk or harm.

5. Surveillance Monitoring Proposal

During the workshop, Staff presented a surveillance monitoring proposal it has discussed internally. The proposal is to consolidate the Commission's current surveillance activities into a surveillance/monitoring program designed to produce information regarding a utility's financial and operational condition now and as expected in the future. Current quality of service reporting would support a portion of the quality of service surveillance/monitoring.

The program is intended to produce contemporary information to support the Commission's case and enforcement responsibilities. Examples of the intended information that would be produced by this program would be periodic reports addressing the overall rate adequacy, causes/reasons for rate deficiencies or excess, quality of service trends and customer class trends on a current basis for jurisdictional utilities.

A large portion of the case-specific work would be performed on a routine basis and provided as minimum filing requirements when cases are filed with Commission instead of producing case-specific information at a later date. The Commission would be more timely informed regarding financial and service quality issues prior to a case being filed. A new forum would be established for issue discussion before a case is filed allowing more latitude in addressing an issue as well as creating a better understanding of the matter at the time the case is filed. (Prior experience has shown how prospective discussion of financing proposals before the filing of a related financing case has shortened processing times in a majority of these cases. This activity was initiated from discussions in a prior Commission workshop.) It is also expected that surveillance/monitoring information would incorporate utility comments regarding its opinion of the material similar to prior management audits.

The specific utilities would have access to Staff's reports on that utility, and Staff would seek comments from the utility on the report. OPC would have access to the information. The other interested parties, including other utilities, would have access to the information contingent upon acceptable safeguards being established to address improper disclosure.

The program should be beneficial to most cases as it provides background material on the utilities operating in Missouri. The program would reduce processing work and assist in issue identification in rate increase cases and will significantly impact the processing of complaint cases concerning excessive rates concerns.

MIEC in its Comments Supporting and Responding supports Staff's surveillance/monitoring report concept, stating, "a robust monitoring/surveillance program available to all parties would be a substantial move towards the transparency that is essential to the efficient resolution of issues in the Commission's regulatory process". OPC, in its Additional Comments, also supports Staff's enhanced surveillance reporting proposal.

6. Trackers/Riders

The Commission has periodically authorized trackers for unusual or new costs. For instance, the Commission promulgated a tree-trimming process in response to repeated outages. Since the cost of implementing the process was unknown, the Commission authorized trackers to track the costs. Similarly, the Commission has authorized riders for such things as recovery related to the MEEIA surcharge and the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM").

7. Construction Accounting/Plant-In-Service Accounting

MEDA recommends the Commission consider allowing construction accounting for all capital investments between rate cases or for the portion of capital investment that exceeds

depreciation expense. According to MEDA, construction accounting allows the utility to continue accruing “AFUDC-like” on its investment until that investment is included in rate base.

Ameren Missouri states construction accounting/PISA allows the electric utility to defer the return and depreciation associated with a capital asset from the time the asset is placed in-service until it can be reflected in rates. According to Ameren Missouri, this treatment will eliminate “permanent losses” associated with the investment. Ameren Missouri indicates that Missouri has occasionally allowed construction accounting for unusually expensive capital items, such as a generating plant or a coal plant scrubber, but states, “The Commission has thus far rejected proposals to apply plant-in-service accounting more broadly.”

8. Interim Rates

MEDA recommends the Commission allow utilities to implement interim rates for some or all of the increases in costs they incur during the pendency of a rate case. The interim rates would be subject to refund dependent on any prudence disallowances or the amount of rate case recovery compared to the interim rate recovery.

According to Ameren Missouri, many states and FERC reduce regulatory lag by regularly allowing interim rates to recover the cost of capital investments, or other costs, in rates during the pendency of a rate case. Ameren Missouri continues, “The Commission has historically utilized a standard for considering interim rates that is so stringent that, in practice, interim rates have simply not been available.”

DE recommends the Commission consider setting standards for the processing and evaluation of interim rate relief. DE states that such standards would provide transparency and certainty to utilities and stakeholders.

In Case No. ER-2010-0036, Ameren Missouri requested interim rates, to go into effect shortly after the case was filed, covering capital projects only. In its Report and Order in Case No. ER-2010-0036, the Commission stated:

The Commission's authority to grant an interim rate increase was recognized by the Missouri Court of Appeals in a 1976 case involving Laclede Gas Company. The *Laclede* decision found that the Commission has an implied power to grant interim rate adjustments under the "file and suspend" provisions of the statutes that require public utilities to change rates by filing tariffs and that allow the Commission to suspend a rate change tariff to allow time to conduct a full hearing to determine whether that tariff will result in just and reasonable rates. Specifically, the *Laclede* decision holds that "the Commission has power in a proper case to grant interim rate increases within the broad discretion implied from the Missouri file and suspend statutes and from the practical requirements of utility regulation."

Thus, the Commission has "broad discretion" to determine whether to grant an interim rate adjustment. In the *Laclede* case, the Commission applied an emergency standard to determine that Laclede was not facing an emergency and thus should not be allowed to implement an interim rate increase. The *Laclede* decision upheld the Commission's use of such an emergency standard against Laclede's contention that the existing rates were so unreasonably low as to result in a confiscation of Laclede's property. However, the decision does not limit the Commission's "broad discretion" by requiring the Commission to use an emergency standard when considering an interim rate adjustment. (Footnotes omitted.)

OPC, in its Additional Comments, is supportive of discussing concepts related to interim rates, "as long as there was also a requirement for interim rates during a complaint case. OPC conducted research and found that 45 states have some form of interim process for rate increases.

It is generally unclear in these proposals what level of sales should be assumed in setting interim rates – those used in the most recent rate case, or those from some other time period.

9. Revenue Decoupling Mechanism

Revenue decoupling is a generic term to describe alternatives to cost-of-service regulation. Not all stakeholders agree what constitutes "revenue decoupling." In the Staff Report

submitted to File No. AW-2015-0282, Staff identified the following examples of revenue decoupling previously approved by the Commission:

- a. Straight fixed variable rate – remove the commodity charge and recover all costs from the customers through a simple fixed charge. In the past, the Commission has authorized this mechanism for some natural gas utilities. It is important to note, however, that the cost of the natural gas itself is excluded from this mechanism. Missouri American Water Company recently proposed rates in which virtually all fixed costs would be recovered via the fixed customer charge, leaving only variable costs to be recovered via the variable rate component.
- b. Increase the customer charge. The Commission has authorized increases to customer charges.

10. Other Changes To Streamline The Regulatory Process

In its Reply Comments, MIEC suggests that to make the regulatory process more efficient, the Commission could: 1) Increase the amount of information required to be filed when a utility files a request for a change in rates similar to that typically requested by Staff; 2) Allow access to confidential information and work papers earlier in the process; 3) Process intervention requests on a shorter timeframe; 4) Reduce the current 20-day discovery response time; 5) Shorten the time between when a utility provides true-up data and when parties respond to that data; and 6) Have a process where non-utility parties respond to the utility filing in direct testimony.

B. Reform Where Commission's Current Authority Is Uncertain

1. Forward test year

- a. Projected/partially forecasted test year

MEDA explains that a forward test year represents a twelve-month period that typically begins about the time a rate case ends so two-year forecasts are required to span the rate case year and the year rates take effect. This concept, according to MEDA, would not apply if interim rates were allowed shortly after the filing of the rate case. MEDA suggests a

“partially forecasted” test year is also an option in which some months of the test year use historic data while some months use forecasted data.

According to Ameren Missouri, many states set rates based on a projected or partially-projected test year in order to align rates more closely with the costs that are actually being incurred during the period when the rates apply.

Missouri is prohibited by § 393.135, RSMo from setting rates based on plant investment before the plant is “fully operational and used for service.” However, according to Ameren Missouri, “There is no statutory prohibition against utilizing projected expenses to set rates, but so far the Commission has not done so.”

OPC recommends a “two-step rate increase” that would recover expected post-order capital additions and identifiable expenses within a certain period of time. The “second step” would be completed after an audit to determine the investment meets in-service criteria and identified expenses have been incurred. According to OPC, “offsets to capital additions, such as additional depreciation on rate base assets and additional deferred income taxes should be used as a deduction from allowable gross investment”.

C. Reform That Requires Legislative Change(s)/Greater Commission Flexibility

1. Revenue Decoupling Mechanism

In the Staff Report submitted to File No. AW-2015-0282, the Staff noted that revenue decoupling mechanisms that ensure the utility’s revenues are protected may require legislative change.

As MEDA comments, the Commission has implemented a form of decoupling for gas utilities through rate designs that allowed the gas utilities to collect more of their fixed costs through fixed charges or low usage blocks. MEDA suggests these gas utility rate designs could

serve as a template for implementing similar rate designs for other utilities. MEDA further suggests decoupling true-up plans to ensure actual revenue tracks the revenue allowed by regulators. According to MEDA, “Most decoupling true up plans have two basic components: a revenue decoupling mechanism (“RDM”) and an allowed revenue adjustment mechanism (“RAM”). The RDM tracks variances between actual and allowed revenue and makes periodic true ups.” MEDA states, true ups can be made annually or more frequently, with more frequent adjustments allowing a better correlation between actual and allowed revenue. This correlation results in fewer rate fluctuations from year to year.

Renew Missouri suggests decoupling “the profit of utilities from their volumetric sales” could result in an environment that “is more prepared to hand the current challenges in the industry”.

- Revenue Stabilization Mechanism

The revenue stabilization mechanism construct is a species of decoupling. MEDA notes, “Between general rate cases, revenue can be stabilized by conservation adjustment or decoupling policies that disconnect the amount of base dollar revenue collected from actual billing unit sales and target revenues to other metrics.’ (Pacific Economics Group Research LLC and EEI, 2013.)”

DE recommends any revenue stabilization mechanism be accompanied by a requirement for utilities to achieve all cost-effective demand-side savings, robust assurances of benefits to customers, prudence reviews, and the ability for customer refunds.

- Allow Construction Work In Process in Rate Base

Presently prohibited by § 393.135, RSMo., the “Anti-CWIP Law.”

- Performance-Based Rates

OPC comments, “Incentive-based regulation can include decoupling measures (that would require aggressive consumer protection measures such as ‘claw-back’ provisions and rate case moratoriums), revenue-cap regulation, or any form of regulation tied to specific performance incentives, such as reliability of service or achievement of specified resource objectives.” While not stating an official OPC policy, OPC provides additional information on performance-based regulation:

In a May 18, 2015 editorial in the Utility Dive web magazine titled “Why Utilities Should Push for Performance-Based Regulation”, authors Ron Lehr and Michael O’Boyle state “(PBR) adds alternative sources of revenue to an otherwise stagnant business model subject to flat or shrinking demand for electricity service, and links shareholder value to customer value by financially rewarding utilities for achieving the outcomes customers want from electricity service. This provides new opportunity for utilities to increase returns and reduce risks if they provide the outcomes customers want, creating a win-win for customers and shareholders.

Renew Missouri suggests that PBR could incentivize the IOUs to meet the needs of the regulatory compact, become more innovative, and provide the IOU a “healthy” rate of return.

- Formula rates

United for Missouri (“UFM”) comments that formula rates provide regulatory certainty, which is “a benefit to investors and customers alike.” UFM suggests the work done by the FERC regarding use of formula rates for transmission service provides guidance for the Commission and Staff in order to “get the details right.”

- ISRS For Electric

The utility stakeholders support an electric ISRS, similar to what is expressly allowed for water and natural gas utilities in §393.1000-393.1015. A similar statute would be necessary to create an electric ISRS.

- Electric Rate Case Adjustment Proceeding
 - a. Utility files traditional 11-month rate case
 - b. May choose to file traditional rate case every 3 years to update Class Cost of Service/Rate Design, Rate of Return, ROE, Capital Structure, Revenue Requirement and Rate Base
 - c. Annual 7-month “rate case adjustment” case to update Revenue Requirement and Rate Base for consumption/expenses (does not include Rate of Return, Capital Structure or ROE)
 - d. Rate case adjustment caps on annual rate increase of 3-5 percent for each class
 - e. Performance incentives and disincentives
 - f. Requires capital investment plans to be submitted.

UFM generally supports the concepts outlined above.

- Decisional Pre-Approval Process With Post-Construction Review
- Grid Modernization Incentive Act
 - a. Establishes a mechanism to allow timely, efficient and prudent cost recovery to utilities for making grid modernization improvements that go beyond regular repair activities
 - b. Establishes a pre-approval process
 - c. Includes performance metrics and milestones
 - d. Includes a floor for minimum investment
 - e. Requires utility to offer Commission-approved demand-side management programs.

DE points out that such a proposal would be consistent with recommendation 3.12 of the Comprehensive State Energy Plan (“CSEP”).

UFM generally supports the concepts outlined above, noting the principles “show[] movement in the right direction.”

V. Targeted Policy Considerations

A. Net Metering

In its comments, Brightergy indicated support for passage of the Senate Committee Substitute of Senate Bill 1028 filed during the 2016 regular session because it included provisions which set the net metering cap at 300 kW, and provided further guidance on solar rebates. Brightergy encourages the Commission to include net metering and solar provisions in any proposed legislation to promote adoption of distributed generation assets. Brightergy notes that customer access to data is necessary to “drive innovation and adoption of new energy technology.”

DE states that the net metering act sets customer-owned renewable distributed energy resources limits which may act as a barrier to adoption of larger systems. DE points out that the statute also does not explicitly allow for virtual net metering, aggregated net metering and third-party resource ownership, and does not describe treatment for CHP and microgrids. Finally, DE discusses the current statutory compensation scheme and suggests “the annual accumulation of credits or debits (rather than monthly accumulation) would better encourage the growth of renewable DERs in the state, as would the evaluation of the “value of solar” and other distributed energy resources.” (Footnote omitted.) DE recommends including additional eligible resources such as biogas and landfill gas renewable energy systems. DE also suggests “discussions should include the potential benefit of off-setting a portion of line extension and

interconnection costs to promote the spread of non-intermittent resource and system deployment of distributed generation over 500 kW of capacity.”

Renew Missouri states that any alternative regulatory structure should maximize the cheapest and cleanest resources available and provide customers with the option of acquiring power from cleaner sources of electricity.

B. Security and Diversity of Supply

DE, citing CSEP recommendation 3.10, addresses diversity and the security of energy supply. DE states that energy supply diversity provides additional opportunities for reliability and security of Missouri’s energy supply infrastructure. DE suggests an accounting mechanism could be considered as an option to allow Missouri utilities to recover costs related to cyber-security.

C. Renewable Energy Standard

In its comments, DE states:

While Missouri utilities are beginning to embrace the transition to renewable energy, some parties oppose this development. These parties contend that renewable energy is not the least-cost resource, that it is not needed for capacity or regulatory needs, or that the energy or renewable attributes can be purchased elsewhere. Parties have cited the RES compliance requirements as evidence that renewable energy is only needed in limited amounts. However, the cost of renewable energy resources continues to decline making them more cost-effective, increased diversity contributes to reliability and security, transitioning to a cleaner energy portfolio positions Missouri well for future environmental goals, and there are economic development benefits from the in-state development of renewable resources to replace aging fossil fuel-fired generation assets.

In order for utilities to fully benefit from maturing markets, the PSC would need to recognize the value of renewable energy resources beyond considerations of the current cost and compliance requirements, such as the benefit in learning by doing as well as avoidance of future regulatory requirements and various other co-benefits. Additionally, renewable energy-fueled CHP systems may not currently be used for compliance, although as system costs decline, CHP potential in

Missouri will increase. To allow for renewable energy-fueled CHP systems to qualify towards RES compliance, the PSC's rules (and DE's rules) would need to be modified (as per CSEP recommendation 3.5). (Footnote omitted.)

The CSEP recommends the RES statute be revised to: strengthen the portfolio requirements to 20 percent of annual retail sales by 2025; clarify the retail rate impact calculation; add renewable energy-fueled CHP systems as eligible resources; and impose reasonable limits on the use of RECs. The CSEP also recommends establishing voluntary RES goals for utilities not currently covered under the law, with the opportunity to demonstrate goal achievement and receive investment credits.

D. MEEIA

According to DE, as of May 2016, 25 states have either “standalone” energy efficiency mandates or allow energy efficiency under the state’s renewable portfolio standards. DE references an American Council for an Energy-Efficient Economy (“ACEEE”) 2016 report which ranked Missouri 31st in per capita spending on electric energy efficiency programs in 2014. DE suggests, consistent with CSEP recommendation 1.1, that there are opportunities for policy modifications that would encourage more aggressive, mandatory energy efficiency targets. DE also recommends that cost-effectiveness testing not be used in Missouri to determine achievement of all cost-effective savings at the portfolio level, DE also recommends additional measures such as CHP and CVR be considered under MEEIA and that customers who utilize low-income housing tax credits be allowed to participate in MEEIA.

The Natural Resources Defense Council (“NRDC”) recommends Missouri “embrace[e] an energy efficiency portfolio standard of at least 1.5 percent per year” and address the throughput disincentive by “embracing revenue decoupling.” Renew Missouri agrees that MEEIA should include a mandatory 1.5 percent annual energy efficiency savings requirement for IOUs, and the throughput disincentive should be eliminated through revenue decoupling.

UFM suggests the best way to align utility financial incentives with helping customers use energy more efficiently is to “adopt a model that has the utility compensated for productive services rendered and not for targets achieved.” UFM also comments that minimizing the initial burden and spreading expenditures over time will allow the customer to compare the costs of the MEEIA program with the energy savings associated with that program.

E. Alternative Financial Instruments for Consumers

Consistent with CSEP recommendation 4.4, DE recommends regulated utilities be encouraged to offer on-bill financing programs. UFM also recommends the Commission explore on-bill financing as an option.

F. Electric Vehicle (“EV”) Charging Stations

According to DE,

[T]he introduction of EVs to Missouri’s electrical grid has caused anxiety among some parties with regards to infrastructure needs, increased demand, and rate design. While these concerns may be valid, various states and utilities are already moving forward with EV adoption by being proactive about their grid needs. For example, Alabama Power provides rebates for both residential customers’ purchases of EVs and commercial customers’ installation of [EVs and their related service equipment] ESVE infrastructure. Illinois provides rebates for ESVE infrastructure development while simultaneously mandating that a charging station must be installed at each interstate highway rest stop. Additionally, more and more municipalities are looking towards EVs to reach federal air quality standards, which will necessitate EVSE infrastructure development.

DE recommends consideration of time-differentiated rates, initiatives where utilities would partner with multifamily buildings to install charging stations, infrastructure cost recovery over the lifetime of EVSE assets as EV adoption increases. DE suggests perhaps EV charging suppliers should not be regulated like traditional electric utilities to encourage free market development, but acknowledges this would require an explicit statutory exemption.

G. Microgrids

Consistent with CSEP recommendation 3.7, DE promotes the adoption of standardized microgrid requirements related to interconnection and how microgrid owners and utilities interact. DE suggests utilities be required to develop tariffs applicable to microgrid that are: 1) not punitive or discriminating, 2) appropriately price various types of standby power, and 3) encourage microgrid development with an initial focus on areas of the grid that are congested or experiencing rapid demand growth. In turn, according to DE, microgrid owners and operators should be required to provide utilities with information that could affect planning.

H. Low Income Rates

DE notes that explicit authority for the Commission to order low-income rates is consistent with CSEP recommendation 2.4. DE goes on to recommend:

In designing a low income rate, to more fully address the challenges facing low-income energy consumers, the Commission may wish to consider the terms of service affecting a low-income rate class. Such authority could address additional measures to improve affordability and to promote service retention and the efficient use of energy, such as affordable repayment plans, arrearage reduction plans, and waivers of miscellaneous fees. Low-income rate participants should also be encouraged to sign up for any available weatherization assistance. (Footnote omitted.)

UFM does not support low income rates, stating, “It is impossible to legislate compassion.” UFM states that Missouri utility law is predicated on the principle of non-discrimination, and any other approach would be confiscation of property. UFM encourages the Commission to consider policies that facilitate private, voluntary methods of assisting low-income consumers, citing the Dollar Help and Dollar More programs as examples.

I. Rate Case Expense Sharing

UFM “strongly opposes” the concept of rate case expense sharing as an arbitrary sharing or partial disallowance of rate case costs.

J. CCN Process

GridLiance Heartland LLC (“GridLiance”) suggests the current “certificate of convenience and necessity” (“CCN”) process largely duplicates the regional transmission operator (“RTO”) process; thus, GridLiance recommends state policy allow a transmission-only utility (“Transco”) to obtain a general CCN, and once granted a CCN, further provide that the Transco should not have to obtain an additional CCN for each project. GridLiance suggests that as long as a transmission project has been studied and approved by an RTO, the state should be satisfied that adequate regulatory oversight has been accomplished and the proposed project is in the public interest. If Missouri policy is not changed, GridLiance recommends a simplified process and notes that the Kansas Corporation Commission (“KCC”) has a statutory duty to rule on a CCN application within 180 days, while the ICC has to rule no later than 150 days after an application is filed.

K. Aging Workforce

IBEW Local 1439 recommends policy be established to address the aging workforce to ensure electric utility companies “maintain a quality, well-trained workforce to properly maintain, construct (to a reasonable level) and monitor their systems.”

VI. Staff Recommendations

A. Regulatory Lag

In its September 6, 2016, Opinion, the Western District Court of Appeals stated, “The best way to account for regulatory lag is a question of methodology and *is best addressed*

by the expertise of the PSC, which this Court will not second-guess.” (Emphasis added.)³⁶ Rate cases are unique in that the utility is in possession of all of the data, and timing of the rate case filing is largely under the control of the utility. Based upon the available information, Staff is not convinced that Missouri utilities have, as a whole, systematically under-earned in recent years due to regulatory lag, even after taking into account the trend of declining sales experienced by Missouri electric utilities. Rather, in Staff’s opinion the most accurate statement of the utility concerns regarding regulatory lag is that the current Missouri ratemaking system allegedly does not provide adequate incentives for utilities to make investments above the “status quo” level necessary to maintain safe and adequate service in Missouri. As a result, according to the utilities, programs such as grid modernization initiatives and accelerated infrastructure replacement activities are not currently being pursued, and likely will not be pursued in the future.

A few comments are in order on this point. The fact that in recent years Missouri utilities may have had to prioritize and choose between various capital addition options due to lack of sales growth or other reasons is not evidence of a “problem” in Missouri regulation; that is exactly how the utilities should respond to this situation. It is a virtue, and not a detriment, if Missouri regulation provides incentives for its utilities to reasonably limit both their construction expenditures and their operation and maintenance expense outlays to the levels they can “afford” while still maintaining safe and adequate service to the customer. In Staff’s view, it should not be the intended purpose of utility rate regulation to automatically exempt utilities from the types of financial pressures routinely faced by competitive businesses. For this reason, Staff does not

³⁶ *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service v. Missouri Public Service Commission*, Nos. WD79125, WD79143 & WD79189 (W.D. Mo. App. Sept. 6, 2016).

view that Missouri utilities currently face any type of regulatory lag “crisis” that demands dramatic action such as sweeping legislative changes. Further, it is only in the context of proposals for aggressive grid modernization or infrastructure replacement that serious concerns regarding regulatory lag may be implicated. Following from that, measures to materially reduce the amount of regulatory lag should as much as possible be targeted specifically toward those types of initiatives.

Notwithstanding the above discussion, Staff is not opposed to consideration of modifications to the current Missouri ratemaking process in order to reduce regulatory lag from current levels, as long as certain principles are followed:

1. Staff supports measures allowing the Commission an enhanced ability to use a variety of tools as part of any regulatory lag reduction efforts.
2. Any re-examination of regulatory lag issues should be focused on the context of increased plant modernization/infrastructure replacement initiatives that may go beyond adherence to the traditional “safe and adequate” service standard, and not just on shifting risk away from utilities for the purpose of making it easier for the utility to reach its authorized return.
3. The ability of the Commission to review and audit the books and records of utilities operating under its jurisdiction should be preserved.
4. The focus should be on efforts to actually reduce the amount of regulatory lag, and not merely shift the economic impact of regulatory lag from the utilities to customers.

5. If the risk faced by Missouri utilities is materially changed by enactment of policy initiatives to reduce regulatory lag, this change in risk should be taken into account in setting the utilities' authorized returns.
6. Any changes should preserve current incentives for utilities to operate efficiently, and not serve to effectively guarantee the utilities a particular return or profit level.
7. Any ratemaking changes to reduce the impact of regulatory lag should preserve the appropriate matching in time of a utility's revenue, expense and rate base values in setting rates to the extent possible.

B. Performance Metrics

The Commission currently has the authority to build some performance incentives into rates, for example, when setting the ROE; however, rates are not automatically updated based on performance. Applicability of additional performance metrics is dependent on the regulatory or policy changes that are ultimately implemented. The Commission should have the ability to determine on a case-by-case basis whether performance metrics are applicable to the particular situation. If performance metrics are deemed appropriate, Staff recommends the Commission consider the following criteria when developing performance metric objectives:

- Objectives should be clearly defined (including how they are calculated)
- Objectives should be challenging but realistic
- Objectives should be measurable
- Objectives should provide the appropriate incentives

Not everything of value readily lends itself to metrics. For example, call center quality is more difficult to effectively measure than call answer times. Deficiencies in utility performance should be identified and a determination should be made as to what, if any, efforts have been made to remedy the deficiencies.

Consideration should be given to continual evaluation of targets and objectives for revisions based on any number of criteria including technological advancements and performance that has improved or remained constant for some period of time.

Thought must be given as to how to measure performance, what reporting will be required and the process to verify and/or audit performance reporting.

C. Possible Statutory/Policy Changes

As Staff previously indicated, it is not convinced that statutory or policy changes are needed to the extent portrayed by other stakeholders. However, to gain a better understanding of utility regulatory concerns and investment needs, Staff met with Ameren Missouri on several occasions. During the Missouri Energy Policy Conference (“MEPC”), Erin O-Connell-Diaz, former ICC Commissioner commented that Illinois “nibbled” around the edges of regulatory reform with tools such as trackers and recovery mechanisms, but that was not sufficient. Illinois is often touted as an example for Missouri legislative and policy changes, yet statements from Ameren Corporation and Ameren Illinois suggest Missouri’s “problems” are not comparable to the “problems” that Illinois faced. Many of the proposed investment opportunities for Missouri may meet the needs of changing technologies or customer focus, and may provide even greater reliability, safety or security than Missouri currently experiences; but, in Staff’s opinion these investment opportunities are being achieved and can continue to be achieved without sweeping regulatory reform.³⁷ Staff recognizes that some modification to the current regulatory environment may be beneficial in promoting grid automation, infrastructure replacement, or encouraging energy efficiency and renewable energy. However, Staff recommends any reform

³⁷ For example, both KCP&L and KCP&L-GMO have deployed AMI metering to their customers, Ameren Missouri was among the first utilities in the country to fully deploy AMR metering to its customers, and all Missouri utilities significantly reinvested and enhanced their distribution systems during the period 2006-2012. New generation and environmental projects have also been brought into service during this time period, often with stakeholder support and non-traditional rate treatment to support investment.

designed to encourage grid automation or infrastructure replacement include a requirement to submit, for Commission approval, a 5-year investment plan, which includes annual progress updates. To properly incent such investments, Staff offers the following recommendations on specific proposals for change.

1. Shortened Rate Case Processing

The Commission shortened the rate case process from 11 months to 10 months for GMO's current rate case. Staff is not opposed to shortened rate case processing as long as all parties continue to be afforded due process, and the ability of the Commission to perform a thorough review and audit of the books and records of utilities operating under its jurisdiction as part of the rate review process is preserved. Enhanced surveillance reporting as outlined by Staff in the workshop and in this report, a requirement to provide responses to standard data requests with the filing of the rate case, more expansive minimum filing requirements, and shortened DR response times are some of the options that could be incorporated in the current process to shorten rate case processing time.

2. True-Up Period

Staff recommends the current true-up process within rate cases continue. It should be noted KCPL argued at the Western District Court of Appeals that, "the PSC's reliance on historical data will fail to reflect KCPL's current expenses when the new rates take effect, which KCPL claims will be higher than historical costs indicate due to a number factors, a phenomenon called 'regulatory lag.'" The Court's Opinion stated, "[A]lthough KCPL complains that the historical test-year model with a true-up period does not adequately take into account regulatory lag, the PSC has adapted its methodology to attempt to account for regulatory lag. The true-up period established by the PSC was designed to remediate some of the negative effects of

regulatory lag by taking into account known and measurable subsequent or future changes to KCPL's expenses."³⁸ Any true-up methodology should account for a mismatch of data, and include both costs and revenues. For instance, due to the manner in which electric utilities supply monthly sales levels to Staff and other parties, that a lag of 6-18 months exists between when a month transpires and when the data is available to calculate weather-normalized sales for that month with reasonable accuracy so some lag is inevitable.

3. Trackers/Riders

Additional trackers could be implemented, as a means to encourage investment, but Staff recommends they be considered on a case-by-case basis based on all relevant evidence. Proposals to apply tracker or rider treatment to normal and ongoing types of utility costs should be subject to strict scrutiny.

4. Construction Accounting/Plant-In-Service Accounting

If application of special ratemaking treatment is deemed to be appropriate public policy for some categories of plant investment, Staff suggests they be used on a case-by-case basis at the discretion of the Commission. Staff further suggests that use of ISRS-type mechanisms to set rates for such investment would be superior to either expanded use of construction accounting or implementation of plant-in-service accounting. Use of both construction accounting and plant-in-service accounting in the nature discussed by the utilities in their comments could offer total protection against regulatory lag for one major component of utility revenue requirement, and accordingly would remove existing incentives for Missouri utilities to act prudently in regard to plant addition decisions. If use of construction accounting or plant-in-service accounting is

³⁸ *In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service v. Missouri Public Service Commission*, Nos. WD79125, WD79143 & WD79189 (W.D. Mo. App. Sept. 6, 2016).

considered by the Commission, Staff recommends that their application be limited to specified discrete categories of plant (for example, accelerated infrastructure replacements or grid automation additions), and be available for use at the discretion of the Commission. Particularly for grid automation additions, it may be appropriate to, in some manner, offset these investments or earnings on these investments with the resultant labor savings. In this respect, it should be noted that Staff is not aware of any other state jurisdiction that has implemented either a construction accounting mechanism or a plant-in-service accounting mechanism on a global basis for all plant additions.

5. Interim Rates

Staff is not opposed to consideration of interim rate increases outside of emergency and near-emergency situations. It may be appropriate to review the current criteria applicable to consideration of interim rates to determine if it should be modified; therefore, Staff agrees with DE recommendation that the Commission consider setting standards for the processing and evaluation of interim rate relief. As DE states, such standards would provide transparency and some certainty to utilities and stakeholders. The decision as to whether to allow an interim rate change should remain with the Commission.

6. Revenue Decoupling Mechanism

Revenue decoupling is a generic term to describe alternatives to cost-of-service regulation. Not all stakeholders agree what constitutes “revenue decoupling.” Staff suggests there may be times when forms of decoupling may be appropriate, such as is currently implemented through MEEIA. Staff does not recommend statutory changes to allow decoupling beyond what is currently allowed under the Commission’s current authority; however, if

statutory changes are deemed appropriate, Staff recommends the Commission be granted authority to use the mechanism at its discretion.

7. Forward Test Year

Missouri is prohibited by § 393.135, RSMo from setting rates based on plant investment before the plant is “fully operational and used for service.” Therefore, absent statutory changes, use of a forward test year cannot result in an appropriately “matched” revenue requirement based on concurrent measurement of a utility’s rate base, expenses, cost of capital and revenues. Staff does not recommend statutory changes to allow a forward test year, but is not opposed to use of partially forecasted test years, where some financial data is included on a projected basis, but that data is trued-up to actual results during the pendency of the rate case. However, if statutory changes are deemed appropriate, Staff recommends the Commission be given discretion on its applicability.

8. Revenue Stabilization Mechanism

Similar to decoupling, revenue stabilization mechanisms can take various forms. Staff does not recommend legislative changes beyond the Commission’s current authority to approve a revenue stabilization mechanism; however, if statutory changes are deemed appropriate, Staff recommends the Commission be given discretion to allow a utility recovery through a revenue stabilization mechanism.

9. Allow Construction Work In Process In Rate Base

While this option was discussed, no stakeholder appears to strongly recommend it as an option. In Staff’s opinion, there are other options to address concerns with the current regulatory environment; therefore, Staff does not recommend statutory changes to modify the prohibition under § 393.135, RSMo., the “Anti-CWIP Law.”

10. Performance-Based Rates

As discussed under the Performance Metrics subsection of Staff's Recommendations, performance metrics may be appropriate depending on the regulatory reform that is implemented. However, in Staff's opinion, a large overhaul to the current regulatory construct to move from cost of service ratemaking to performance-based ratemaking is not justified at this time. In Staff's opinion, there are other options available to address concerns with the current regulatory environment; therefore, Staff does not recommend statutory changes to implement performance-based rates. Although Staff is not recommending PBR, similar to Illinois, any legislative changes authorizing such methodologies should include mandatory commitments for grid automation above and beyond those investments to provide safe and adequate service, and should also include a requirement for permanent job creation including consideration of job reductions associated with the automation effort. Performance metrics should include a penalty for not meeting the mandatory commitments. Rewards should be based on meaningful improvement to safety, reliability or security. Finally, the Commission should be granted discretion in applying PBR.

11. Formula Rates

In Staff's opinion, a large overhaul to the current regulatory construct to move from cost of service ratemaking to formula ratemaking is not justified at this time. On a historical cost ratemaking basis, use of formula rates would transform the ratemaking process from its current forward-looking emphasis to an emphasis of allowing the utility to recover a past-recorded cost of service level and, as such, would reduce the effectiveness of current incentives for prudent and efficient utility behavior. In Staff's opinion, there are other options available to address concerns with the current regulatory environment; therefore, Staff does not recommend statutory changes

to implement formula rates. However, any legislative changes authorizing formula rates should include mandatory commitments for grid modernization above and beyond those investments to provide safe and adequate service, and should also include a requirement for permanent job creation. Performance metrics should include a penalty for not meeting the mandatory commitments. Rewards should be based on meaningful improvement to safety, reliability or security. Finally, the Commission should be granted discretion in applying formula rates.

12. ISRS For Electric

Staff is not opposed to an electric ISRS if it is implemented similar to what is expressly allowed for water and natural gas utilities in §393.1000-393.1015, and the Commission retain authority to review the application. The existing ISRS mechanism for Missouri water and natural gas utilities applies only to clearly defined subsets of utility plant additions, takes into account both positive and negative rate base changes associated with qualifying plant additions, and mitigates (but does not entirely eliminate) the impact of regulatory lag associated with those utilities' covered plant additions. Any implementation of an ISRS-type mechanism for electric utilities should follow the same general rate recovery format for applicable categories of plant investment. ISRS mechanisms should not be so broad as to cover all of a utility's plant investment, or ongoing amounts of "normal" or "status quo" plant investment.

13. Electric Rate Case Adjustment Proceeding

- a. Utility files traditional 11-month rate case
- b. May choose to file traditional rate case every 3 years to update Class Cost of Service/Rate Design, Rate of Return, ROE, Capital Structure, Revenue Requirement and Rate Base

- c. Annual 7-month “rate case adjustment” case to update Revenue Requirement and Rate Base for consumption/expenses (does not include Rate of Return, Capital Structure or ROE)
- d. Rate case adjustment caps on annual rate increase of 3-5 percent for each class
- e. Performance incentives and disincentives
- f. Requires capital investment plans to be submitted.

This proposal is a variation of the type of formula rate plan that was the subject of recent legislative discussion. Staff views this particular proposal more favorably than earlier models for two primary reasons: (1) There is no “reconciliation” rate adjustment to automatically restore the utility to or near a pre-determined return on equity; and (2) there appears to be more of an ability for rate case participants to raise concerns with the Commission regarding the utility’s costs than there would be under other formula rate formats.

The utility parties raised two primary concerns regarding this proposal in their comments. First, the utilities stated that this process would actually increase the amount of regulatory lag incurred by utilities compared to the current regulatory process. Second, they comment that the annual rate caps are too stringent, and that certain costs should be exempt from the caps.

Regarding the first objection, Staff observes that formula ratemaking will almost always result in a cost cut-off for rate purposes of a greater duration than the five month average lag that currently exists in Missouri³⁹, and hence increase that measurement of regulatory lag. In response to that phenomenon, utilities may propose that “reconciliation rate adjustments” be used as part of a formula rate plan to automatically move the utility to or very close to a pre-established return on equity value in order to offset regulatory lag impacts. Staff opposes use

³⁹ However, formula ratemaking plans would still provide the utility with more frequent and more certain rate changes than under traditional rate regulation.

of reconciliation rate adjustments as such adjustments are a disincentive for utility efficiency. However, if the Commission were to give credence to the utility comments on this point, it could consider use of a reconciliation adjustment feature utilizing a reasonable “deadband.” A “deadband” in this context is a return on equity value for which no rate adjustment is allowed under the formula rate plan. As an example, assume a utility has an authorized ROE of 9.5 percent, and a deadband value of plus/minus 100 basis points for formula ratemaking purposes. If the utility’s actual earnings for the year were calculated to be anywhere in a range from 8.5 percent to 10.5 percent, it would not be allowed an annual adjustment to its rates within the formula plan. If the utility’s earnings were below 8.5 percent or above 10.5 percent, it would only be allowed to adjust its rates in order to earn 8.5 percent or 10.5 percent, respectively. Use of deadbands in this context would preserve some incentive for efficient operations on the part of the utility, and appear to be common in other states with formula rates.

As for the utility objections to the rate cap provisions, Staff’s interpretation of this proposal is that the caps would not include net fuel/purchased power costs, renewable costs, energy efficiency costs or environmental compliance costs that are currently, or can be, recovered through single-issue rate mechanisms in Missouri. These items can result in material rate impacts, either individually or in tandem. Taking the possible rate impact of these single-issue mechanisms into account, granting of further upfront rate cap exemptions for other categories of utility costs is not warranted.

14. Decisional Pre-Approval Process With Post-Construction Review

Staff recommends the Commission incorporate a decisional pre-approval process in its CCN rule (4 CSR 240-3.105), with a post-construction review of the costs and timeline to

complete the project. This process will provide the utility some assurance of recovery, while maintaining the Commission's authority to review the implementation details of the project.

15. Grid Modernization Incentive Act

- a. Establishes a mechanism to allow timely, efficient and prudent cost recovery to utilities for automating the grid and making grid modernization improvements that go beyond regular repair activities
- b. Establishes a pre-approval process
- c. Includes performance metrics and milestones
- d. Includes a floor for minimum investment and a ceiling consistent with a multi-year plan
- e. Requires utility to offer Commission-approved demand-side management programs.

To the extent that this mechanism operates in an identical or similar manner to the existing ISRS mechanism for water and gas utilities, Staff recommends this option as a reasonable approach for special rate recovery of electric grid automation improvements.

D. Targeted Policy Considerations

1. Net Metering

Stakeholders propose net metering and solar provisions be included in any proposed legislation to promote adoption of distributed generation assets. Staff is not opposed to properly designed net metering and solar provisions, but is concerned about continued cost recovery from all ratepayers, including low income ratepayers, for products that can only be implemented by a portion of the customer base.

2. Security and Diversity of Supply

Staff is not opposed to an accounting mechanism as an option to allow Missouri utilities to recover costs related to cybersecurity and infrastructure security if those costs are above and beyond what would be incurred in the normal course of business. Any use of accounting mechanisms for this purpose should be reserved for material incremental cybersecurity and infrastructure security costs and should be reviewed on a case-by-case basis.

3. Renewable Energy Standard

Staff does not have an opinion on whether the RES should be increased, but is concerned about the impact of cost recovery on ratepayers.

4. MEEIA

Staff is opposed to a mandatory energy efficiency portfolio standard. Chapter 22 optimizes the use of demand-side and supply-side resources through integrated resource analysis of alternative plans with diverse and robust set of alternative resource plans.

5. Alternative Financial Instruments for Consumers

Staff is not opposed to exploring whether regulated utilities should be encouraged to offer on-bill financing programs.

6. Electric Vehicle (“EV”) Charging Stations

Staff made the following recommendations in File No. EW-2016-0123:

- EV charging stations and their operation are generally within the jurisdiction of the
- Commission.
- If ratepayer recovery of network implementation, operation and maintenance costs is
- considered:
 - IOUs consider mandatory TOU rates for all public charging stations and for EV owners.
- To learn from the pilot projects, Staff recommends the IOUs gather data and report annually to the Commission and interested stakeholders on the impact of EVs on grid reliability as items such as:
 - EV Load Leveling

- Did the load increase overnight due to EV charging?
 - Did the load level as a direct result of the EV charging network?
 - Did the EV load allow the utilities to spread out fixed generation cost and recover over a greater amount of electricity sold?
 - Impact on customer bills due to EV load and the resulting load leveling?
 - Did the EV network prevent periods of over-generation?
 - Did the EV network smooth out large load ramps in the morning and evening?
- The IOUs explore various emerging technologies and their impact on the areas of demand-response, supply-side resourcing and second battery life programs.

7. Microgrids

Staff does not have an opinion on recommendations related to the adoption of standardized microgrid requirements related to interconnection and how microgrid owners and utilities interact; however Staff will note that at MEPC, a speaker commented that microgrids do not pay for themselves, noting microgrids are resiliency dependent, not price/payback dependent. Therefore, Staff is concerned about the rate impact to ratepayers related to cost recovery of microgrids.

8. Low Income Rates/Additional Residential Rate Classes

Staff is not opposed to legislation giving the Commission authority to review proposals related to low income rates. Today there exists different classes of commercial and industrial customers that were created when it was deemed appropriate. A low income residential class could assist in addressing the issue of utility affordability for low income residential customers. An enhanced energy residential class can be designed to address customers that want and are willing to pay the costs of receiving such options as renewable energy choices and net metering. At the same time, residential customers who are satisfied paying for the service they have today could retain this option.

9. Rate Case Expense Sharing

Staff recommends the option for the Commission to order “sharing” of rate case expenses, or to otherwise assign a portion of incurred utility rate case expenses to shareholders, should be preserved to ensure that utilities are provided adequate incentives to hold their expenditures in this area to reasonable levels and that captive customers are not saddled with excessive costs.

10. CCN Process

Staff suggests issues related to the CCN process be considered in the context of the CCN rulemaking

11. Aging Workforce

Staff suggests a policy to address the aging workforce to ensure electric utility companies “maintain a quality, well-trained workforce to properly maintain, construct (to a reasonable level) and monitor their systems is outside the Commission’s purview, and could be viewed as “micro-managing” the utility.