REPORT OF THE

INTERIM COMMITTEE

ON

UTILITY REGULATION

AND

INFRASTRUCTURE INVESTMENT

December 28, 2016

Prepared by:

Kayla Hahn, Missouri Senate, Division of Research

December 28, 2016

The Honorable Ron Richard
State Capitol, Room 326
Jefferson City, Missouri 65101

Dear Mr. President:

The Senate Interim Committee on Utility Regulation and Infrastructure Investment, acting pursuant to the Senate Rule 31, gathered information from a variety of sources in order to compare the current regulatory oversight process of electric, natural gas, water, and sewer utility services in Missouri to that of other states. The Committee also examined ways that the utility regulatory process in Missouri may be modernized to be more efficient and effective in order to ensure sustained investment in utility infrastructure while at the same time promoting the interests of fairness among all constituencies. The Committee heard testimony from the Public Service Commission, Office of Public Counsel, the Department of Economic Development – Division of Energy, investor-owned utilities, consumer groups, environmental groups, and various other interested parties during August and October 2016. Summaries of the testimony and supplemental information are included in this report.

There is widespread interest in the oversight process of regulated utilities in this state. The Interim Committee expresses gratitude to the Public Service Commission, Office of Public Counsel, the Department of Economic Development – Division of Energy, investor-owned utilities, consumer groups, environmental groups, and other parties who provided vital information to the Committee during the hearings.

The undersigned members of the Senate Interim Committee on Utility Regulation and Infrastructure Investment are pleased to submit the attached report.

For the Senate:

Ed Emery

Ed Emery, Chairman

Jeanie Riddle 10

Jeanie Riddle

Gary Romine

Jason R Holsman

Jason Holsman

Gina Walsh

Gina Walsh

Ryan Silvey

Ryan Silvey, Vice-Chairman

Bob Onder

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Wayne Wallingford

Wayne Wallingford

Scott Sifton

Letter from the Chairman
December 28, 2016

The Honorable Ron Richard
State Capitol, Room 326
Jefferson City, Missouri 65101

Dear Mr. President:

During the 2016 legislative interim, you tasked me with Chairing the Senate Interim Committee on Utility Regulation and Infrastructure Investment. In the course of such time, the Interim Committee has gathered information from a variety of sources in order to compare the current regulatory oversight process of electric, natural gas, water, and sewer utility services in Missouri to that of other states. Additionally, the Committee examined ways that the utility regulatory process in Missouri may be modernized to be more efficient and effective in order to ensure sustained investment in utility infrastructure while at the same time promoting the interests of evenhandedness among all constituencies.

Several key points have emerged during the duration of the Interim Committee. First and foremost, a number of states are moving to utility regulatory models outside of the traditional process. This can be the result of many changing phenomena including but not necessarily limited to the following:

- Customers are demanding more control over the source and cost of their electricity by installing smart thermostats and solar panels, and by choosing electric vehicle transportation;
- The future for utilities – especially energy – has shifted from a growth model to a conservation model. Volumetric demand has been steadily declining, leading to less need for large generation units and financially disincenting utilities to make substantial infrastructure investments;
- Increasingly stringent environmental mandates have forced utilities to examine their energy generation portfolios, leading to increased renewable and natural gas generation and early retirements of some coal-fired generation units; and
- Electricity flow is no longer uni-directional. With expanding innovations in distributed generation, customers are demanding that the grid become a manager of electron flow not just a transporter.

Other states have already begun adopting more progressive utility regulation mechanisms to address both a changing utility environment and evolving consumer demands as those consumers begin to appreciate the unrealized value of a next generation electric grid – a grid that is not just a means of delivering electricity, but a valuable asset, one that can be optimized to meet these new and rapidly changing consumer demands. By neglecting to recognize and respond to the modern utility model, Missouri's policies are falling behind other states utility mechanisms for infrastructure investments and Missouri's energy prices continue to increase at a rate beyond that of other similarly situated states (see chart on page 5). Utility investment dollars are finding other states more predictable, more adaptable, and more attractive. These deficiencies don't harm investors, they can invest elsewhere; the harm is to Missouri families and businesses that are unable to benefit from the modern grid.

Second, there are several benefits to moving beyond a traditional utility regulatory process. Under the current regulatory model, both utilities and consumers face a certain set of difficulties. Utilities, on one hand, are reliant heavily upon revenues derived from highly unpredictable customer usage based on weather patterns. Utilities are also not able to recover revenues in a timely manner due to regulatory lag, even when such expenses are deemed to be reasonable and prudent. Consumers, on the other hand, face unpredictable utility bills with multiple varying charges and riders. Additionally, consumers are not given any assurance relating to utility costs in the future; that is, how much a utility bill may increase over a given period. Price and cost transparency are essential to consumers that want to make wise and beneficial decisions regarding their energy usage. Under a newly designed regulatory process, the difficulties faced by both the utilities and consumers could be addressed.

Finally, it is time for Missouri to invest in its infrastructure, its utilities, and its citizens. Missouri was named by the Edison Electric Institute as one of the least progressive states when compared to all other states based upon electric utility mechanisms for infrastructure investment. In response, it is time that we adopt new policy alternatives that will benefit both utilities and consumers. Additionally, a modern electric grid is the key to economic development in Missouri, allowing for inestimable potential in new job growth, innovation, and sustainability. Regardless of which of the policy alternatives are chosen to revitalize our electric grid, we should ensure that our policies are non-discriminatory in terms of technology, individual preferences, and economics, with our policies determined by the marketplace and citizens. Further, our new utility regulatory policy and process must facilitate the innovation and continued evolution of utility infrastructure by allowing flexibility, creativity, and being customer-driven. At the end of the day, the citizens of the state of Missouri will benefit.

In closing, I would like to thank you for the opportunity to serve as the Chairman of the Interim Committee on Utility Regulation and Infrastructure Investment. I look forward to discussing several policy alternatives as a result of this Interim Committee during the 2017 legislative session.

Regards,

Ed Emery

Senator Ed Emery
Chairman

Changes in Electric Rates in the 50 States Since 2007

	June 2007/¢/kWh			June 2016/¢/kWh			Increase	
1	West Virginia	5.14	1	Louisiana	7.05	1	Texas	-20.2%
2	Idaho	5.16	2	Washington	7.57	2	Louisiana	-15.6%
3	Wyoming	5.27	3	Oklahoma	8.02	3	Nevada	-12.6%
4	Washington	6.22	4	Wyoming	8.29	4	New York	-7.2%
5	Kentucky	6.27	5	Kentucky	8.42	5	New Jersey	-4.4%
6	Indiana	6.46	6	Arkansas	8.44	6	District of Columbia	-4.4%
7	Nebraska	6.69	7	Texas	8.44	7	Delaware	-3.9%
8	North Dakota	6.76	8	Idaho	8.47	8	Maine	-3.0%
9	Arkansas	6.78	9	West Virginia	8.74	9	Florida	-2.8%
10	Oregon	6.84	10	Nevada	8.82	10	Maryland	0.2%
11	Utah	6.96	11	Oregon	8.82	11	Massachusetts	3.8%
12	South Dakota	7.03	12	Mississippi	8.83	12	Oklahoma	5.4%
13	Iowa	7.10	13	Indiana	9.06	13	Illinois	5.7%
14	Tennessee	7.14	14	Montana	9.15	14	Mississippi	6.0%
15	South Carolina	7.22	15	Tennessee	9.29	15	Pennsylvania	7.8%
16	Virginia	7.28	16	North Carolina	9.31	16	New Hampshire	8.1%
17	New Mexico	7.50	17	Illinois	9.32	17	Connecticut	8.5%
18	Kansas	7.54	18	North Dakota	9.45	18	Hawaii	14.8%
19	Oklahoma	7.61	19	New Mexico	9.51	19	Montana	19.1%
20	**Missouri**	**7.62**	20	Virginia	9.63	20	California	19.5%
21	North Carolina	7.68	21	Nebraska	9.69	21	Ohio	20.3%
22	Montana	7.68	22	Utah	9.71	22	Rhode Island	20.6%
23	Alabama	7.92	23	Ohio	9.77	23	Vermont	20.8%
24	Minnesota	8.08	24	Alabama	9.86	24	North Carolina	21.2%
25	Ohio	8.12	25	Florida	10.01	25	Washington	21.7%
26	Colorado	8.17	26	Pennsylvania	10.04	26	Georgia	23.0%
27	Georgia	8.23	27	South Dakota	10.10	27	Arkansas	24.5%
28	Mississippi	8.33	28	Minnesota	10.12	28	Alabama	24.5%
29	Louisiana	8.35	29	Georgia	10.12	29	Minnesota	25.2%
30	Wisconsin	8.74	30	South Carolina	10.13	30	Michigan	25.5%
31	Illinois	8.82	31	Iowa	10.20	31	Arizona	25.7%
32	Arizona	8.82	32	Colorado	10.30	32	Colorado	26.1%
33	Michigan	8.88	33	Kansas	10.93	33	New Mexico	26.8%
34	Pennsylvania	9.31	34	Delaware	11.05	34	Oregon	28.9%
35	Nevada	10.09	35	Arizona	11.09	35	Wisconsin	30.1%
36	Florida	10.30	36	Michigan	11.14	36	Tennessee	30.1%
37	Texas	10.57	**37**	**Missouri**	**11.18**	37	Virginia	32.3%
38	Delaware	11.50	38	Wisconsin	11.37	38	Kentucky	34.3%
39	Vermont	12.02	39	District of Columbia	11.85	39	Utah 39.5%	
40	Maryland	12.31	40	Maryland	12.33	40	North Dakota	39.8%
41	District of Columbia	12.39	41	Maine	12.45	41	Indiana	40.2%
42	Maine	12.83	42	New Jersey	14.21	42	South Carolina	40.3%
43	Alaska	12.86	43	Vermont	14.52	43	Iowa 43.7%	
44	Rhode Island	13.28	44	New York	15.00	44	South Dakota	43.7%
45	California	13.59	45	New Hampshire	15.16	45	Nebraska	44.8%
46	New Hampshire	14.02	46	Rhode Island	16.02	46	Kansas	45.0%
47	New Jersey	14.87	47	Massachusetts	16.04	47	Alaska	45.8%
48	Massachusetts	15.46	48	California	16.24	**48**	**Missouri**	**46.7%**
49	New York	16.17	49	Connecticut	17.63	49	Wyoming	57.3%
50	Connecticut	16.25	50	Alaska	18.75	50	Idaho	64.1%
51	Hawaii	20.81	51	Hawaii	23.90	51	West Virginia	70.0%
	U.S. Total	9.47		U.S. Total	10.53		U.S. Total	11.2%

Footnotes:

All Sector Data from Energy Information Administration (EIA.Gov)

June 2007 through June 2016

Report

The Interim Committee on Utility Regulation and Infrastructure Investment

Table of Contents

Introduction

Pursuant to Senate Rule 31, President Pro Tempore Ron Richard established the Senate Interim Committee on Utility Regulation and Infrastructure Investment on May 25, 2016. The Committee was charged with "conducting in-depth studies and making appropriate recommendations concerning how the current regulatory oversight process of electric, natural gas, water, and sewer utility services in Missouri compares to that of other states." Further, the Committee was charged with examining "the ways that the utility regulatory process in Missouri might be modernized to be more efficient and effective in order to ensure sustained investment in utility infrastructure while at the same time promoting the interests of fairness among all constituencies, including consumers and shareholders of regulated utility companies." The Committee was also assigned the task of issuing "a report as to [the committee's] findings and recommendations, as approved by a majority of members of the committee, to the President Pro Tempore of the Missouri Senate no later than December 31, 2016…". This report seeks to fulfill this obligation.

On August 23, 2016, the Senate Interim Committee on Utility Regulation and Infrastructure Investment convened for its first meeting in Senate Committee Room 2. On that day, the Committee heard testimony from several individual witnesses representing environmental groups, utilities, legal institutes, consultants, and consumers. Similarly, on August 24, 2016, the Committee convened for its second meeting in Senate Committee Room 2 and heard individual testimony from the Missouri Public Service Commission, utilities, consultants, other state utility commissioners, the Missouri Division of Energy, consumers, and solar energy advocates. The Committee then met for a third time on October 25, 2016 for the purposes of hearing individual testimony. On that day, the Committee heard testimony from a non-profit organization that assists states in formulating energy policy, and from the Missouri Public Service Commission regarding a summary of the Staff report on policies to improve electric utility regulation in Missouri. An executive session was also held, during which Chairman Emery posed specific questions to Committee members allowing each member to respond individually. Topics discussed in the executive session included ideas for specific modifications of the current regulatory process for utilities, the timeline for legislative action during the forthcoming legislative session, and specific questions that must be addressed in any legislative compromise. Such questions and individual member responses are enclosed in this report.

This report proceeds as follows. First, individual testimony presented to the Committee is detailed for each of the three hearing days. Such testimony is either in the form of a summary of an individual's verbal testimony or written testimony provided to the Committee. Second, as previously mentioned, Chairman Emery posed questions to members of the Committee prior to the October 25, 2016, hearing date. Such questions and member responses were then discussed during the executive session of the October 25, 2016 hearing. The questions, and any formal responses to such questions, are enclosed in this report. Third and finally, this Committee has set forth a list of recommendations based upon both the testimony and facts presented during the Committee hearings.

Individual Testimony*
August 23, 2016

1. Ashok Gupta, National Resources Defense Council*

Mr. Ashok Gupta serves as a Senior Energy Economist for the National Resources Defense Council (NRDC). The NRDC is a national non-profit organization with over 500 staff members that focuses on environmental regulation at the state level. NRDC seeks to accelerate the shift from fossil fuels to clean energy by promoting policies that limit carbon pollution and promote energy efficiency. Mr. Gupta argues that utility infrastructure is important for both reliability and safety, and that utility infrastructure can also assist customers in making better decisions regarding their energy use habits. Further, Mr. Gupta acknowledges that policymaking in the legislative environment requires balancing – that is, resources are not unlimited with cost being a determining factor but with such costs being detrimental to reliability.

As a result of policy challenges, Mr. Gupta articulated that many states have deregulated the generation portion of the electric utility business, thus allowing large customers to choose their provider; however, as a result volatility has increased. Under the deregulated model, both transmission and distribution are still regulated by the public utility commission. With such model, Mr. Gupta argues that, on the distribution side many customers self-generate power. This, in turn, has been difficult for utilities to accept under the traditional regulatory model. Utilities still have to build to peak load, plus redundancy, due to a lack of energy storage simply because energy has to be generated and used instantaneously.

Mr. Gupta contended that along the pathway from generation to distribution, we also should think about efficiency. He stated that a coal fired power plant is about 40% efficient, a gas plant is about 60% efficient, a combined heat and power plant is about 90% efficient, plus consumers waste around 10% of their electricity. He argues that the best way to do this is to use a performance-based approach to regulate what we want in terms of output, and what we want to incentivize, rather than regulating input. He argues that the traditional regulatory model for utilities should undergo a transition to be regulated similarly to a service business, with such regulation reducing or eliminating regulatory lag, requiring less rate cases, and using a mechanism that has a regular adjustment in utility rates.

2. Karl McDermott, Center for Business and Regulation, University of Illinois, Ameren Distinguished Professor

The purpose of my presentation today is primarily informational, that is – What is happening policy wise around the nation? The purpose of my presentation today is also explanatory, that is – How mechanisms work within the regulatory paradigm. I will review factors driving regulatory change and the range of policy alternatives currently employed to address these factors.

There is a need for enhanced recovery mechanisms for utilities to operate efficiently. For example, utilities are facing a changing environment including safety issues, productivity

* Written testimony is used in this report, unless none was provided. In such case, a summary of testimony is used and is indicated with an asterisk. For purposes of this report, power point presentations were considered to be written testimony.

improvements, storm recovery and the effects of weather on system outages, and reduced consumption and demand. For illustration of this changing environment, please refer to the following graphs:

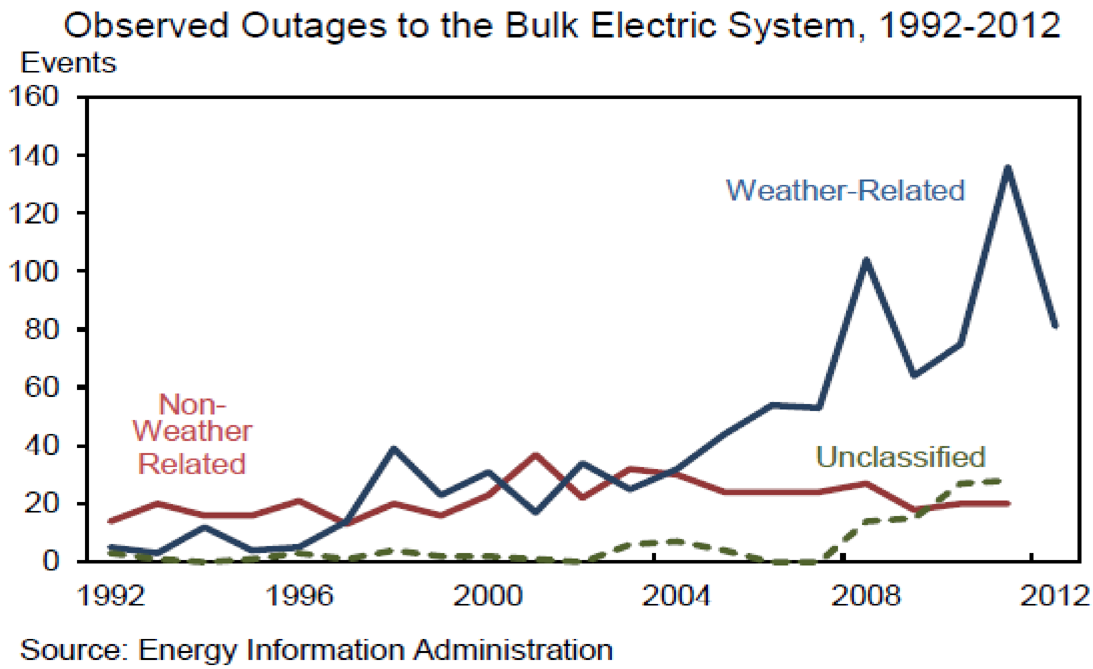
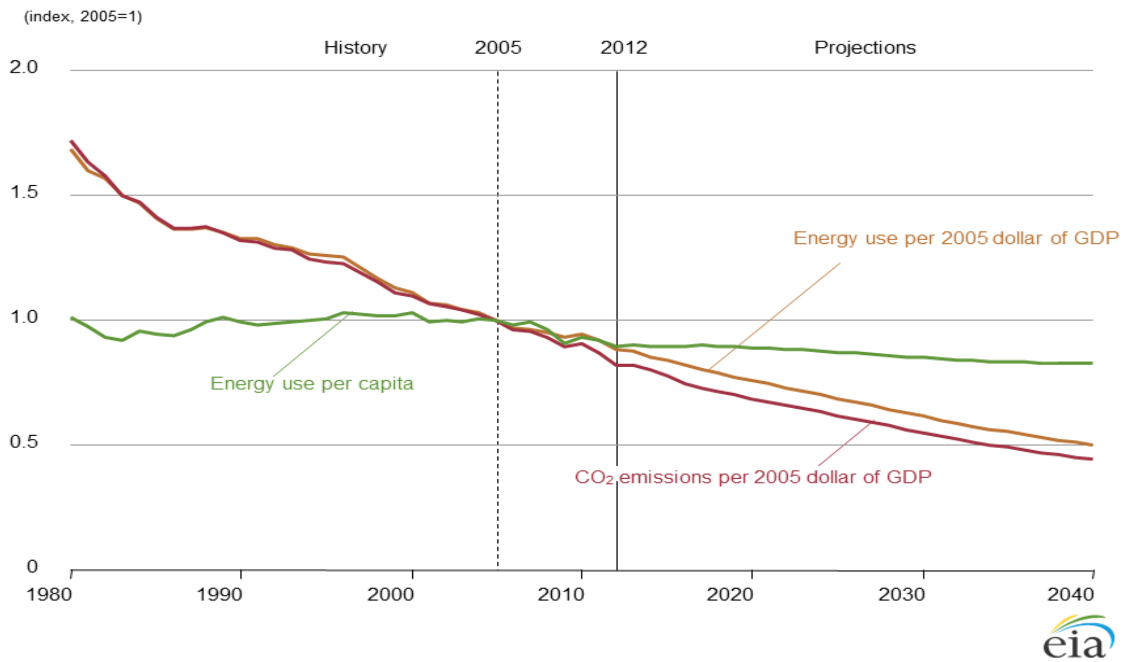


Figure 9. Energy uses per capita, energy use per dollar of GDP, and emissions per dollar of GDP, 1980-2040



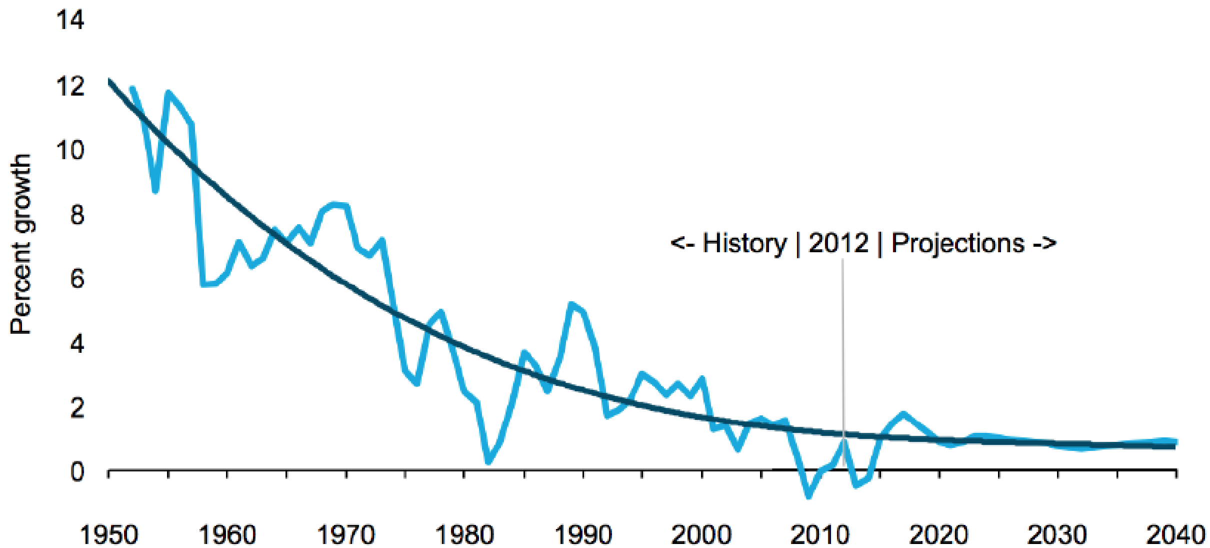
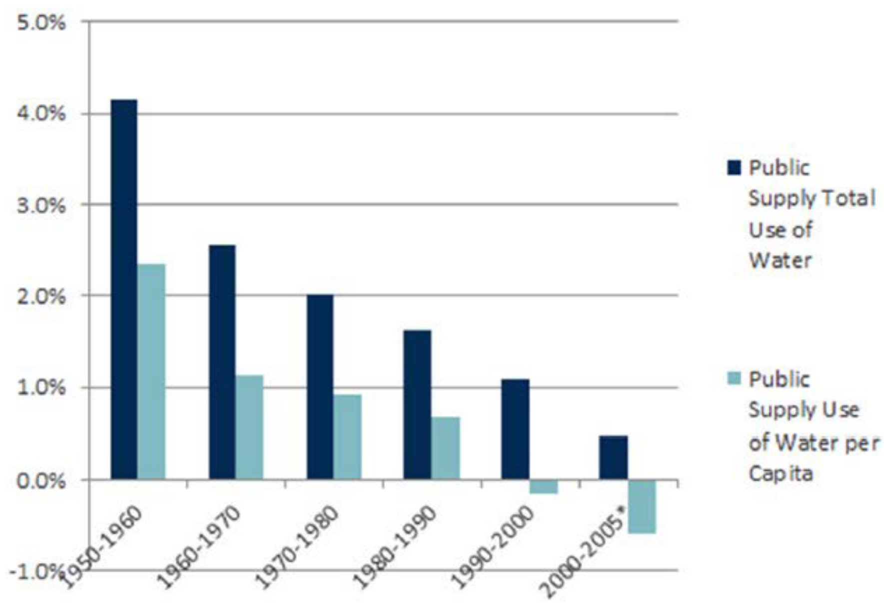


Figure 1. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average). Figures beyond 2012 are projections and not actual data. *Source:* EIA 2013e.

Figure 3.3: Trends in Annual Growth Rates of Public Supply Water in Total Use and Use Per Capita in U.S., 1950 – 2005[29]



As a result of these challenges, regulation has been geared toward certain objectives: energy efficiency investment, conservation, intelligent systems such as grid modernization and smart technology, and outcome-focused performance.

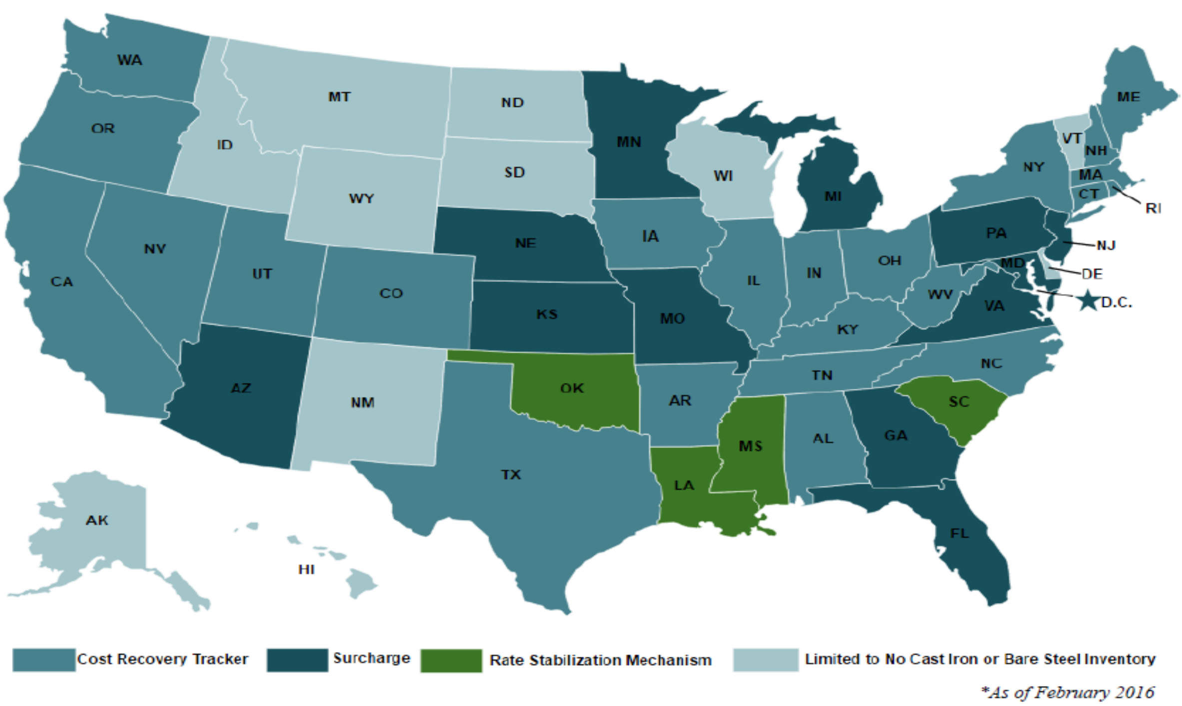
Under the traditional regulatory model, the revenue requirement of the utility is calculated as follows:

$$RR = OC + T + d + r\,(V-D)\ [+/-\text{surcharge, rider, tracker}]$$

Where:
RR = Allowed Revenue Requirement
OC = Operating Costs
T = Taxes
d = Annual depreciation
r = Rate of return
V = Value of plant and equipment
D = Accumulated/accrued Depreciation

Under the traditional rate design, utilities can undercover if customers become more efficient or consume less energy. There are also a variety of mechanisms available to deal with the changing environment faced by the utilities, such as surcharges, trackers, Construction Work in Progress (CWIP), test years, rate design modification including formula rates, multi-year rates, and performance and earnings sharing mechanisms. Under formula rates, rates can be adjusted based upon known costs in an annual rate case and can be adjusted for inflation, with the result matching revenues to costs every year. In Missouri, the current mechanisms employed include surcharges, trackers, rate design, a partially forecasted test-year may be employed, and earning sharing performance regulation.

Attachment 6: States with Accelerated Infrastructure Replacement Programs



As a result, there are many other mechanisms that Missouri may employ to overcome the challenges faced by the utilities in a changing environment.

3. Eric Thornburg, President and CEO, Connecticut Water Service, Inc.

My name is Eric Thornburg and it is my privilege to lead Connecticut Water Service, Inc. (CTWS). CTWS provides high quality drinking water and world class customer service to families and communities in 76 cities and towns across New England. We serve over 400,000 people.

This is my 34th year in the drinking water profession, having served with water service providers in Pennsylvania, Indiana, and Missouri prior to joining CTWS in 2006. I am also a past President of the National Association of Water Companies (NAWC), an organization representing private and investor owned water utilities nationwide. Our member companies serve over 73 million people across the United States.

I am passionate about the drinking water profession. Water touches everything that we care about. It provides for the health of our families, their safety through fire protection, the economic development of our communities and the quality of life enhancements that come through its natural beauty. Water truly changes everything.

Water utilities have a unique responsibility in sustainably managing water resources while providing for public health and safety. This requires the efficient and effective management and stewardship of the water infrastructure that serves customers today. It also includes the systematic replacement of these systems as they reach the end of their useful lives. This will allow future generations to likewise enjoy this precious resource.

There are a number of unique facts about water utilities and the infrastructure our communities rely on for public health and safety:

- There are over 50,000 drinking water utilities nationwide. Most are small, with over 75% serving less than 3,300 customer connections.
- Water utilities are highly capital intensive, requiring considerable investment in plant and equipment to produce safe and adequate drinking water service. Water and wastewater systems are more than twice as capital intensive as electric and gas utilities.
- Aging infrastructure is a major issue for our nation. Water utilities have a significant challenge in this regard. Eighty percent (80%) of our systems can be found in the buried assets that convey the water from the source to the tap. Much of this pipe was installed during the growth of suburban America after the conclusion of World War II. This pipe must now be replaced.
- Experts refer to this as the “replacement era”! We have over 700,000 miles of water mains in the nation. Each year, water utilities should be replacing at least 1-2% of these assets in order to achieve a 100-year replacement cycle. The capital needs will keep coming year after year for decades.
- With the deteriorating state of buried pipe across the US, there are over 240,000 water main breaks and two trillion gallons of treated water lost every year at an estimated cost of $2.6 billion.

- The U.S. Environmental Protection Agency (EPA) and the Government Accountability Office (GAO) estimate the current water infrastructure funding gap to be as high as $1 trillion through 2050. Over 65% of that is needed to replace water mains reaching or past the end of their useful life.
- In addition to the EPA and GAO assessments, the American Society of Civil Engineers (ASCE) gave the U.S. water and wastewater infrastructure a "D minus" as part of its infrastructure report card. According to the ASCE, if left unchecked, these conditions could cost businesses $147 billion and cost households $59 billion. ASCE also notes that under a worst-case scenario, the U.S. could lose nearly 700,000 jobs by 2020.

In response to this significant challenge, the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution in 2013 that recognized the important role of innovative regulatory policies in facilitating the efforts of water and wastewater utilities to address their significant infrastructure investment challenges.

Founded in 1889, NARUC is a non-profit organization dedicated to representing state public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, power, water, and transportation.

NARUC's resolution stated that the traditional cost of service ratemaking, which has worked reasonably well in the past for water and wastewater utilities, no longer adequately addressed the challenges of today and tomorrow.

Public utility commissioners from across the United States recognized that the traditional cost of service model is not well adapted to a declining or nonexistent demand growth, high investment utility environment, and was unlikely to facilitate the necessary year-over-year investment in infrastructure replacement.

NARUC emphasized that alternative regulatory mechanisms would enhance the efficiency and effectiveness of water and wastewater utility regulation by reducing regulatory costs while providing the predictability and regulatory certainty that supports the attraction of debt and equity capital at reasonable costs.

It is against this backdrop that the states of Connecticut and Maine passed legislation that has materially changed the manner in which utilities replace infrastructure. In 2007, Connecticut passed the Water Infrastructure and Conservation Adjustment (WICA). Maine passed the Water Infrastructure Sustainability Charge (WISC) in 2013.

Infrastructure Adjustments

The legislation in Connecticut was designed to enhance the state's capital supportive climate in order to promote investment in water systems. This capital would accelerate the replacement of aging infrastructure, improve system reliability, replace undersized pipes, and reduce the amount of water lost due to leaks, while fostering economic development and creating high-paying, skilled jobs. The legislation was developed with consultation from the state's consumer advocate to ensure there were appropriate customer safeguards incorporated into the process.

Connecticut's WICA requires water utilities to conduct an infrastructure assessment report (IAR) that demonstrates the system needs and develop a water main replacement prioritization model and file them with the Connecticut Public Utility Regulatory Authority (PURA). Once approved by PURA, the utility may proceed with the systematic replacement of pipe, service lines, hydrants, and other assets that promote water and energy conservation. WICA also covers the necessary improvements for systems acquired by larger utilities in order to improve water service to the acquired customers. This feature of the legislation was designed to create a further incentive for larger water systems to acquire smaller, poorly capitalized utilities that struggle to finance the necessary infrastructure replacement.

Maine's WISC goes one step further and covers all water infrastructure including wells, tanks, and water treatment plants that require replacement. Both states have seen significant increases in the rate of asset replacement since these tools have been put in place.

Connecticut's criterion for ranking projects was established through a generic docket before PURA, and has been established to include the following factors:

- Main Breaks – break history and outage impact;
- Pipe Age / Useful Life – age, material, location, and expected life;
- Material Integrity – known issues with materials, unaccounted for water losses, leaks;
- Critical System Impact – impact on customers of potential failure;
- Water Quality Issues;
- Hydraulic Capacity – pressure & volume complaints/operational issues, fire flow adequacy;
- Scheduled Work Coordination – with state or town projects with potential for restoration/paving savings; and
- Other (To be Specified by the Applicant) – Unique customer or community considerations or other mitigating or unanticipated factors or conditions.

Once the work is completed, the utility can then file for an adjustment to the WICA surcharge that appears on all customer water bills.

The WICA adjustment is calculated as a percentage, based on the original cost of completed eligible projects multiplied by the applicable rate of return, plus associated depreciation and property tax expenses related to eligible projects and any reconciliation adjustment calculated as a percentage of the retail water revenues approved in its most recent rate filing for the regulated activities of the water company.

The surcharge can be modified twice a year and is capped at 10%. Typical adjustments for Connecticut Water are 1 – 3 % per year. In the eight years our program has been in use, we have averaged less than 5 customer complaints per year regarding the surcharge.

Since its inception, Connecticut Water has replaced 99.7 miles of pipe with an average age of just over 75 years. We have seen a 19.2% reduction in unlined cast iron pipe in service. We have reduced the amount of galvanized steel pipe in use by 80.2%. A reduction of 56.5% of the pipe less than 4 inches in diameter has also been achieved. Notable improvements in water quality, main break, leakage reduction, and improved fire flows are already evident.

My company is now replacing 15 miles of pipe per year, which is approximately 1% of our piping inventory. Prior to the implementation of WICA, we were replacing no more than 4 miles of pipe per year, which is roughly a 375-year replacement rate. Many of the municipal utilities in our state which are not regulated by PURA lag considerably on their replacement cycles because of the reluctance to seek rate cases to recover the costs. This simply defers the problem for the next generation, or until an operational or water quality crisis forces the investment. The tragedy that occurred with the water system in Flint, Michigan is just one indicator of what can occur when there is a lack of capital and investment in a water system.

Additionally, we have not had to file a General Rate Case (GRC) since 2010. Without WICA, we would have filed at least two general rate cases to recover the annual capital outlays of approximately $12-15 million per year.

A typical rate case costs Connecticut Water about $800,000 and spans six months, which is one of the shorter statutory periods in the United States. By contrast, Missouri takes 11 months – significantly longer and costlier. Maine's GRC process typically takes 4-6 months, but the WISC program has likewise changed the frequency of such filings.

Importantly, the cost of rate proceedings is recovered from customers in nearly all states, Missouri included. In Connecticut and Maine, our legislators and regulators agreed that rather than burdening the state agency's limited staff, utilities committing their staff, paying the attendant legal costs, and hiring rate case experts with frequent full rate case proceedings, customers should benefit from the saving that could be realized through additional investment in the infrastructure that serves them. The era of GRC's is coming to an end and customers, communities, and the environment are the winners.

Additionally, the Connecticut Department of Economic Development reviewed our annual pipeline replacement program to better understand its economic impact. They determined that our program directly created 157 full-time construction or related jobs in the state – a great additional benefit for our economy.

There are significant and important consumer protections built in to the process as well, including:

- The company has to demonstrate the needs of their system through the initial Infrastructure Assessment Report and the subsequent prioritization mode, and then the priority list for eligible projects is subject to review with each filing for a surcharge;
- All costs for completed WICA projects are reviewed and subject to a prudency test by PURA before a surcharge is approved;
- The company must also submit an Annual Reconciliation Report (ARR) to the Department on or before February 28th of each year to reconcile the WICA charges or credits applied to customer bills in the prior year; and
- If the department determines that a water company over-collected or under-collected the WICA adjustment, the difference between the revenue and costs for eligible projects will be recovered or refunded, as appropriate, as a reconciliation adjustment over a one-year period.

The process is all conducted in hearings open to the public and customer communication is required. An explanation of the charge is provided on each customer's bill and there are regular communications to customers about the projects and the benefits of the WICA program. It has been a great tool for addressing the infrastructure challenge.

Besides Connecticut and Maine, the following states have varying versions of the infrastructure surcharge in use:

1. Illinois
2. Indiana
3. Ohio
4. New York
5. Pennsylvania
6. New Jersey
7. Delaware
8. New Hampshire
9. Tennessee
10. Arizona
11. North Carolina
12. Nevada
13. Rhode Island
14. Missouri – Missouri passed the Infrastructure System Replacement Surcharge (ISRS) in 2003, which is narrower than other mechanisms and only applies to St. Louis County. My understanding is that the mechanism is currently in jeopardy due to a drop in the County's population, which of course has not lessened the need for infrastructure investment.
15. West Virginia – The West Virginia PSC encouraged West Virginia American Water to file for a DSIC mechanism. The case is currently pending.

I would urge the State of Missouri to support the use of capital supportive mechanisms like WICA and WISC that hold utilities accountable for delivering sustainable asset management plans. It's a low cost approach to incenting infrastructure investment without taxpayer dollars or subsidies. That makes it a win for customers and communities, while making Missouri more competitive with other Midwest states.

Water Revenue Adjustment Mechanism (WRAM)
If you stop and think about it, water utilities have traditionally benefited financially by selling more water. I suspect we would all agree that this runs somewhat counter to common sense and in conflict with a number of broader public policy goals. Water is a precious natural resource and, by its very nature, limited. The production and distribution of water is also very energy intensive by its nature, so reducing water demands can support energy conservation goals.

I grew up in St. Louis and fully understand how fortunate some parts of Missouri are in regards to water supply. At the same time, our customers, regulators and those of us in the profession all recognize that the right thing to do is to use water wisely and efficiently. It makes long term sense to sustainably manage the resource and to be a good steward of it.

Historically however, if we encouraged customers to use less water, our organizations suffered financially. Water utilities, in addition to being highly capital intensive, also have a high proportion of fixed costs. Small incremental reductions in sales can result in acute financial pressure on the water utility. In response, you find that they must reduce capital outlays, defer maintenance and/or make other financial adjustments to operations in order to compensate for the loss of revenues.

As supply constraints increase and the cost of treating water continues to rise, water utilities have an increasing responsibility to encourage the wise use of this precious resource. The use of more efficient plumbing fixtures and appliances, such as low-flow toilets and showerheads, among other factors, will support a drop in per capita consumption over time.

At the same time, when utilities act as responsible stewards of water resources, they increase the financial pressure on themselves as fixed costs must still be recovered despite decreasing sales volumes. One solution to this challenge is the concept of "decoupling" rates from sales volumes, which can help address both the need to more efficiently use water while keeping the utility financially sound. The electric power industry has experienced similar issues with regard to demand-side management programs designed to better control the need for new generating capacity or the use of high priced fuels.

In Connecticut and Maine, we partnered with regulators, consumer advocates, business organizations, customers, and the environmental community to make a dramatic step in the evolution of drinking water regulation in New England. As a result, our company is no longer in the business of selling water! We are in the business of providing drinking water service.

With the passage of the legislation authorizing a Water Revenue Adjustment Mechanism (WRAM) in Connecticut in 2013, we no longer benefit financially by selling water. Our revenues are capped at what was approved in our most recent rate case. We only recover those revenues as approved by PURA in our most recent rate case, regardless of weather or customer growth. To ensure fairness, customers will get a refund if we sell too much water. Further, there is an earnings sharing mechanism with the customers if an over-collection results in the company exceeding our PURA authorized rate of return.

Conversely, we are permitted to apply a surcharge on customer bills to recover the minimum allowed annually by our regulators. That surcharge is applied the following year.

In the 3 years since the passage of the WRAM, we have surcharged customers about 2% - 4%. At the same time, we are seeing a gradual reduction in our overall system water delivery. The current trend line is a year-over-year reduction in delivery of about 1.5%. This is occurring through customer education, appliance replacement, better technology, and a general conservation ethic that is evident among our customers. This will translate over time into dramatic savings in source development, pumping, storage, and stress on the natural environment.

Given the strength of this program, we have instituted a pilot customer water conservation promotion. If a customer who enrolls in the program uses 10% less water in 2016 than they did in 2015, we will give them a $30 credit on their bill. So far, among the 5,000 customers who 8 signed up for the program, about 40% have achieved the goal and they have saved over 9 million gallons through the first 6 months of 2016.

The WRAM bill had broad support from PURA and the Connecticut Office of Consumer Council (OCC), with supporting testimony submitted by the Connecticut Department of the Environment and Energy (DEEP), Rivers Alliance of Connecticut, Sierra Club, Connecticut Fund for the Environment, and the Nature Conservancy. It was also a priority for the League of Conservation Voters. It was recognized as providing significant environmental and energy conservation benefits. At the same time there were customer safeguards built into the process and the opportunity for customers to further benefit in the long term with reduced water demands allowing for the delay or avoidance of additional supply development.

In addition to Connecticut and Maine, California, Nevada, Indiana, and New York have instituted varying forms of WRAM's for water utilities. According to the Brattle Group, 27 states have similar mechanisms in place for electric utilities and 30 states for natural gas.

Prospective Test Years

In a rising-cost industry with heavy capital investment requirements, the use of historic test years almost assures there will be no return on, or recovery of, capital that is invested during the test year and thereafter until the utility files another rate case. Any return on such investments could therefore be delayed for a number of years. This discourages necessary investment during these periods and skews construction and investment timing based on artificial test year issues rather than system needs and efficient construction planning processes.

Due to regulatory lag, strictly historical test years can virtually ensure that the utility does not earn its allowed rate of return, thereby increasing risk and the cost of capital.

From a regulatory and public policy perspective, the touchstone for test years should be whether they produce rates that are prospectively relevant; that is, that the rates most accurately reflect the costs during the period the rates are most likely to be effective.

A "best practice" in this area would provide the utility with the obligation to identify the most prospectively relevant test year and the choice to use that test year in a rate proceeding. The utility would have the choice of utilizing a historic, current, or future test year and would have the burden of demonstrating the propriety of that choice in the rate proceeding. The use of future test years would have additional filing and proof requirements associated with them to assure that any projections are reasonable. Any party could of course challenge the utility's choice of test year.

Connecticut allows utilities to utilize the most recent 12-month period, which synchronizes rates and investment quite well.

According to the Brattle Group, 19 states have adopted a future test year in regards to water utility rate recovery.

Acquiring Troubled Water Systems

With over 50,000 water systems in the United States, there is a clear need for consolidation. According to the Missouri Department of Natural Resources, there are 1,426 community water systems across the state.

In order to meet the significant capital requirement challenges water utilities face, the achievement of scale is paramount. One regulatory tool that states can utilize is allowing for an acquisition adjustment in water rates.

An acquisition adjustment provides for the difference between depreciated original cost and a purchase price to be recovered by the acquiring utility through the rates it charges, offset by the cost savings of the combination or utility plant investment avoided.

Pennsylvania, Connecticut, and other states explicitly allow acquisition adjustments for small and/or troubled systems, subject to certain conditions, and at least four states (Illinois, Indiana, Pennsylvania, and Missouri) have enacted laws that specify an appraisal process for determining the fair market value. In addition, Connecticut allows for an acquisition surcharge to be imposed on customers of acquired systems if there are significant costs incurred to bring the system into compliance after neglect and artificially low rates by the prior owner.

A basic "best practices" principle regarding water system acquisitions could be stated as follows: "If and to the extent a business combination produces identifiable savings, service improvements, or other benefits to customers, shareholders should have the opportunity to recover and earn a return on the investment required to produce those benefits."

In this concept, the difference between depreciated original cost and a fair market purchase price represents the investment necessary to produce benefits and would be treated similarly to other investments the utility makes to provide cost effective, reliable service.

Methods to achieve this goal could include acquisition adjustments to rate base or the ability of the utility to retain quantified savings resulting from the combination equivalent to a return of, and on, the investment necessary to produce the savings.

My company has acquired 40 water systems in 10 years, partially due to the fact that we have an opportunity to make our case before the PURA for the inclusion of the premium in rates.

Customer rates and service are also lower and better than they would have otherwise been under the prior ownership. This is an important regulatory tool that should be available to meet the small water utility challenges states face.

Rate Consolidation

Connecticut has a goal of achieving standard tariff pricing for each utility. Rate consolidation, or single-tariff pricing, has been recognized as the norm for electric, natural gas, and telephone utilities. These utilities often serve large territories where the costs of service can be substantially different from region to region within the service territory.

For example, costs of service for urban customers will be different from rural customers and differing geographic terrains impose different costs. Yet all customers in a particular class enjoy the same rates. This has allowed these industries to spread the benefits of economies of scale to all of their customers and to mitigate rate shock effects and affordability concerns.

Although single-tariff pricing has at times been controversial for water utilities, it should nonetheless be recognized as a "best practice" — especially in view of the challenges facing the industry in the future. The inability to charge uniform rates inhibits the acquisition of troubled utilities, can result in rate shock or unaffordable rates to customers in certain areas, and significantly increases the complexity and cost of regulatory proceedings, all to the detriment of customers, the utility, and sound public policy.

The states of Pennsylvania, Florida, Idaho, Arizona, California, Delaware, Kansas, Louisiana, Massachusetts, Montana, New Hampshire, New Jersey, North Carolina, Ohio, Oregon, South Carolina, Texas, Washington, West Virginia, Indiana, Illinois, Iowa, and Missouri have all adopted this approach in varying forms.

Conclusion

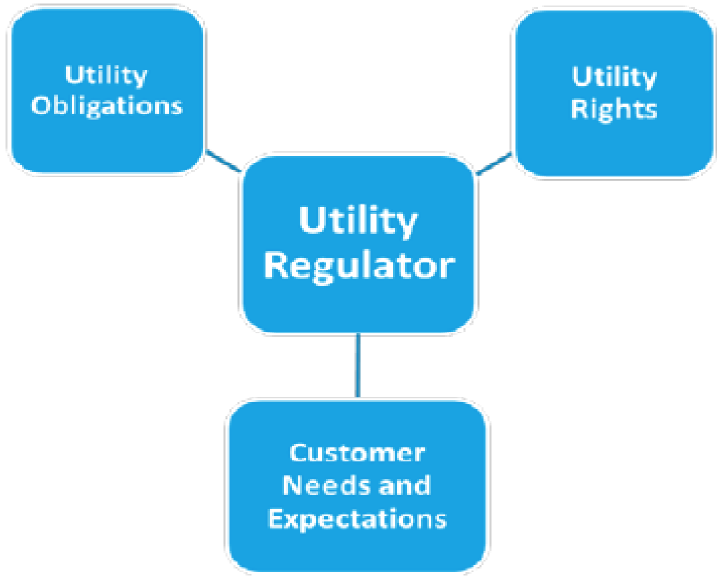
It's been my honor to appear before you here today. I hope that my testimony contributes to the dialogue in a meaningful way. I would close by stressing the need for Missouri to embrace more capital supportive regulatory constructs. Water is the one utility service that is ingested by the public. The actions your utilities take today, investing in critically needed infrastructure will impact the cost of water for future generations. Your investor-owned utilities stand ready to make these investments, and they do not need tax dollars to do it. All that is needed is for the Missouri legislature and the various stakeholders to work together and adopt and tailor the tools that are already proven in other states. The status quo does not work and will result in higher costs for future generations and perhaps the loss of trust in the safety and reliability of their water service and supply.

Thank you very much!

4. Russell Feingold, VP, Black and Veatch

Today's discussion will focus on three topics: the changing gas industry environment has created a number of key business challenges faced by gas utilities over the past several years, the changes that are needed to past utility ratemaking practices and the resulting ratemaking mechanisms implemented by gas utilities, and the progression and status of regulatory and ratemaking reform in the U.S. for gas utilities.

The key regulatory and ratemaking objectives for today's natural gas utility industry is to find the right balance necessary in the regulatory compact to provide both returns for utility investors consistent with the financial marketplace and to protect the interests of customers from excessive rates. Each gas utility will face its own combination of factors that drive the fundamental requirements embodied in the regulatory compact, and these factors must be recognized. In each case, the fundamentals of just, reasonable, and non-discriminatory rates must be satisfied by the regulator and that judgment must be safeguarded in a rapidly changing cost environment to ensure the regulatory compact functions as required. This is best illustrated as:



The gas utilities' business challenges and the resulting impacts may best be illustrated as:

Gas Industry Macro Trends

- Rising and volatile gas prices, then more available gas supplies and lower prices from new sources
- Weather variability and warming temperatures
- Increased focus on energy efficiency, environmental issues and integrity management
- Changing demand sources (e.g., power generation/DER, CHP, NGVs)
- Escalating operating costs for labor and materials
- Significant infrastructure investment required to address integrity management and environmental matters
- Stagnant economic conditions and artificially low interest rates
- Increasing first cost of gas appliances

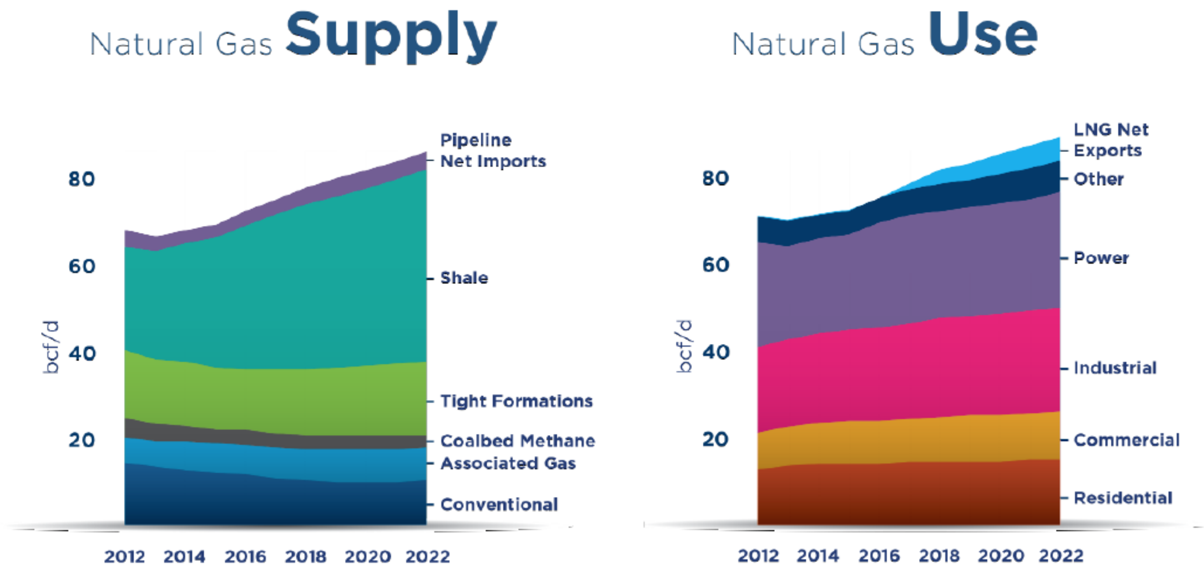
Business Challenges for Gas Utilities

- Declining use per customer
- Increasing regulatory requirements - safety issues and maintenance and improvement of aging infrastructure and system reliability
- Considerable and recurring variability, unpredictability and uncontrollability related to a gas utility's costs of delivery service and gas usage factors
- Inadequate approaches to growth, expansion and economic development
- Customers' ability to pay, lack of customer growth, and demographic changes with variability in the economy
- Obligation to serve requirements (service continuity issues)
- Policy objectives of stakeholders pertaining to utility ratemaking have changed causing more difficulty in reaching balanced regulatory decisions

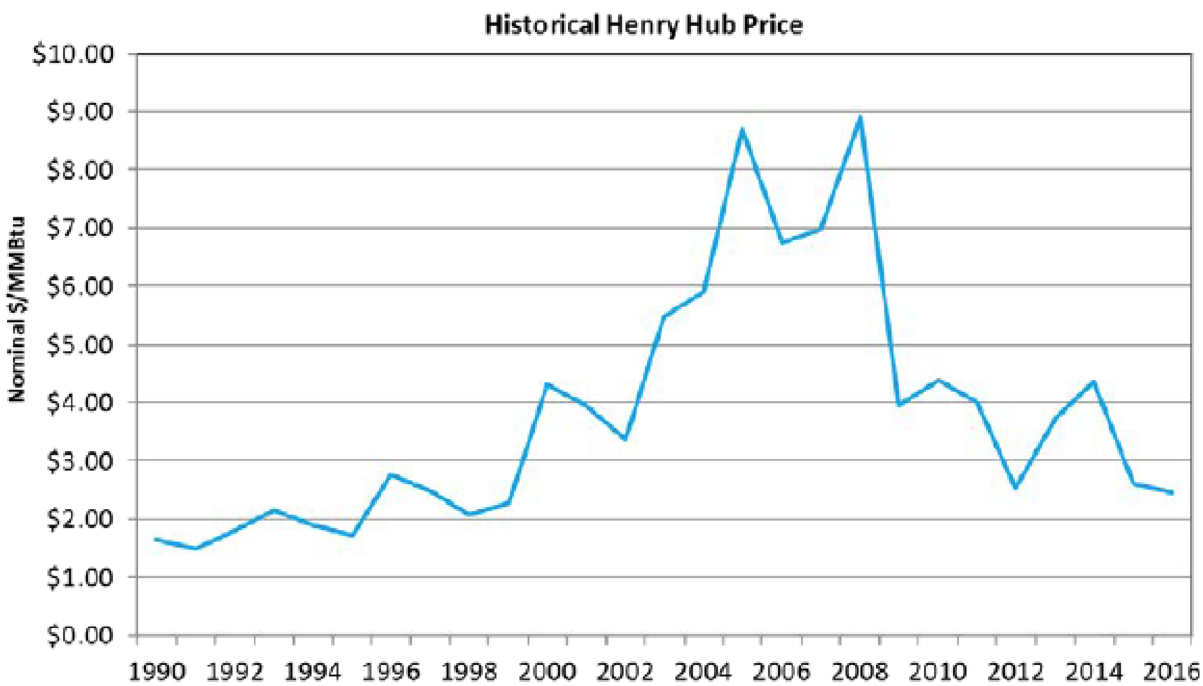
Resulting Impacts

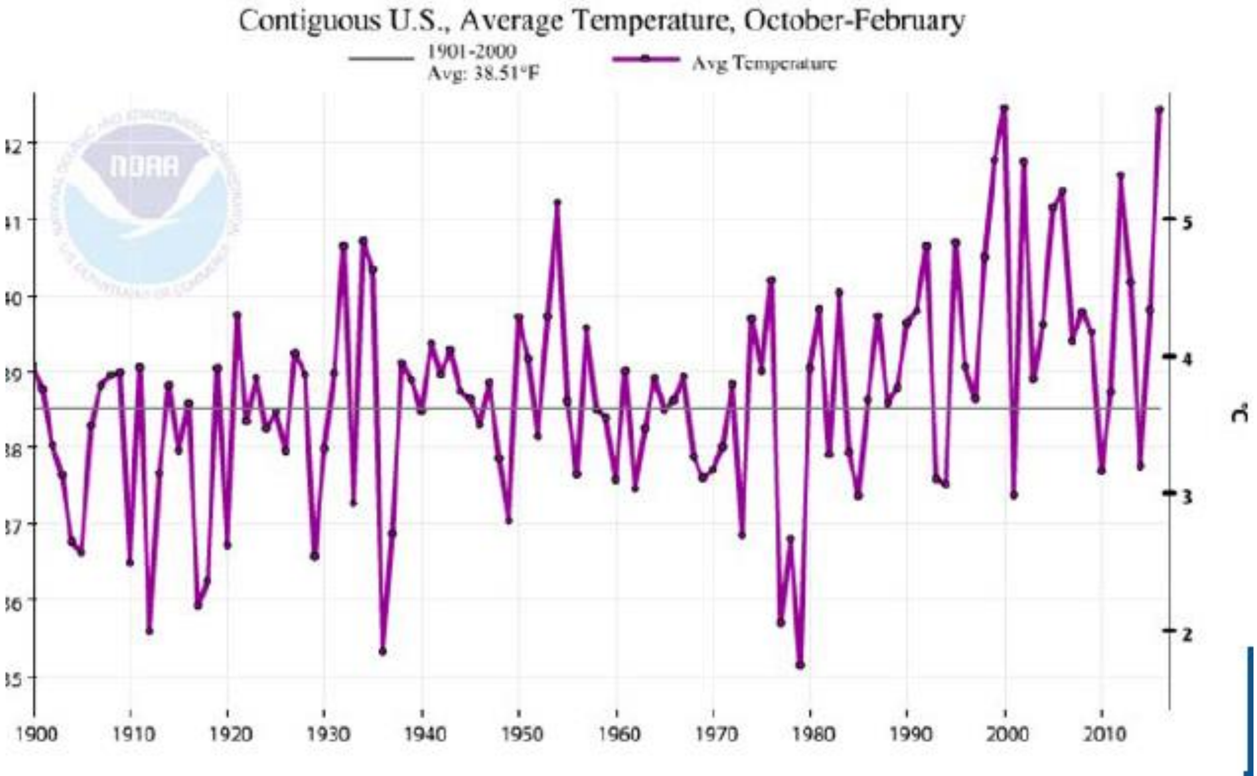
- Increased regulatory lag and earnings attrition
- New stress and challenges for regulators - more frequent, complex, and larger rate cases
- Increases and volatility in customers' gas bills as a result of gas prices (less so in recent times)
- Inability of gas utilities to fully recover their approved revenue requirements
- Chronic under earning by gas utilities (i.e., below average return on equity)
- Customers paying more or less than expected for gas service due to fluctuations in weather from "normal" conditions
- Customers paying more or less than reasonable relative to the utility's actual cost to serve

There are also significant changes in gas supply and demand. For the next decade and beyond, domestic natural gas supplies are expected to be sufficiently robust to meet growth in demand across all sectors. This is best illustrated as:



Gas price and weather volatility can also be best illustrated as follows:



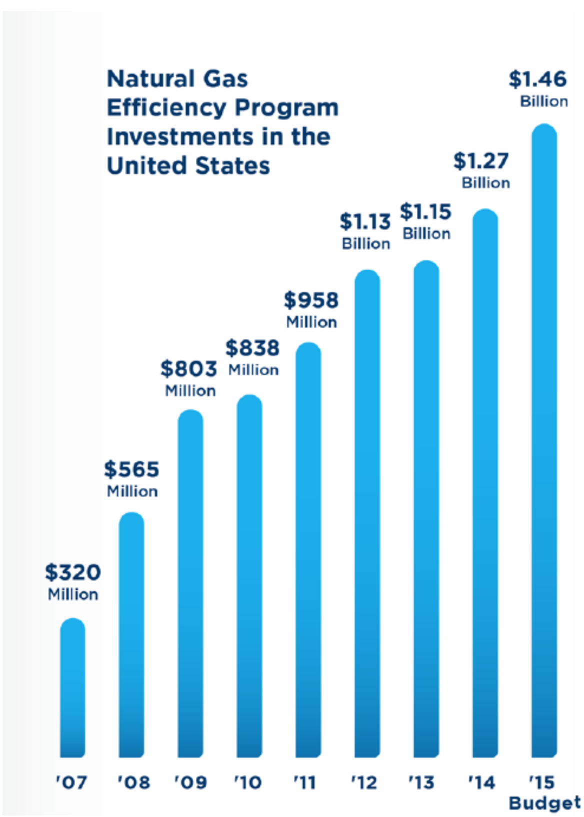


In 2013, NARUC passed a resolution stating:

"RESOLVED, That the Board of Directors of the National Association of Regulatory Utility Commissions…*encourages regulators and industry to consider sensible programs aimed at replacing the most vulnerable pipelines as quickly as possible along with the adoption of rate recovery mechanisms that reflect the financial realities of the particular utility in question*; and be it further;

RESOLVED, That State commissions should explore, examine, and *consider adopting alternative rate recovery mechanisms as necessary to accelerate the modernization, replacement and expansion of the nation's natural gas pipeline systems*."

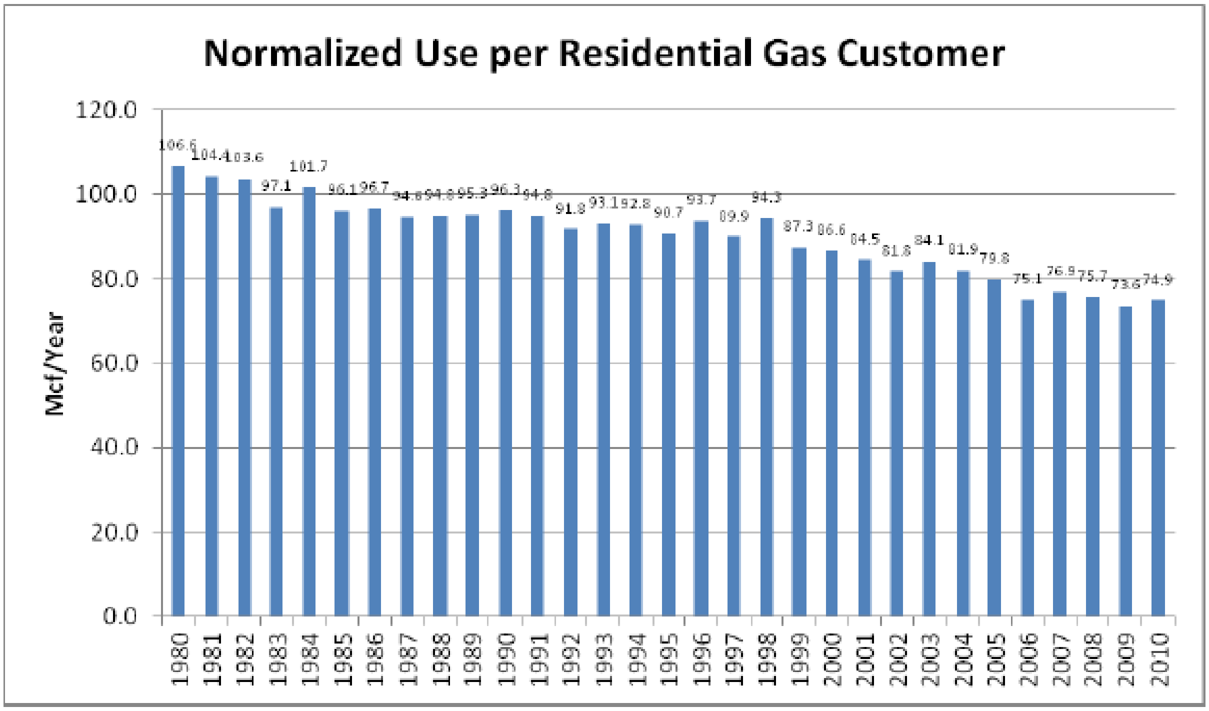
As a result, the gas industry has made significant investments in infrastructure as well as energy efficiency, as illustrated by the following:

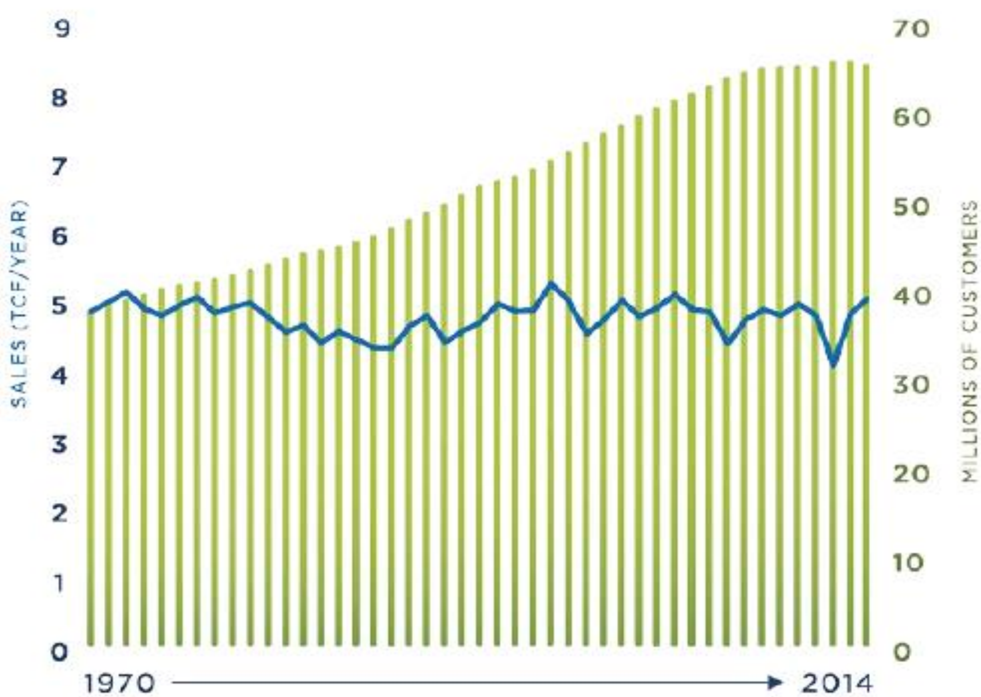


Site-Specific Efficiency of Natural Gas Appliances		
Appliance Type	1972	2006
Gas Furnace	65%	84%
Condensing Gas Furnace	-	96%
Gas Water Heater	50%	67%
Tankless Gas Water Heater	-	80%

Source: Lawrence Berkeley National Laboratory, July 2007.
Notes: Shipment weighted averages; rating by Average Fuel Use (AFUE)

As a result, there has been both declining and variable gas usage over time with energy efficiency programs having a positive impact for customers. While the total number of natural gas homes are up nearly 50% since 1980, the average consumer is using 30% less natural gas compared to 1980.



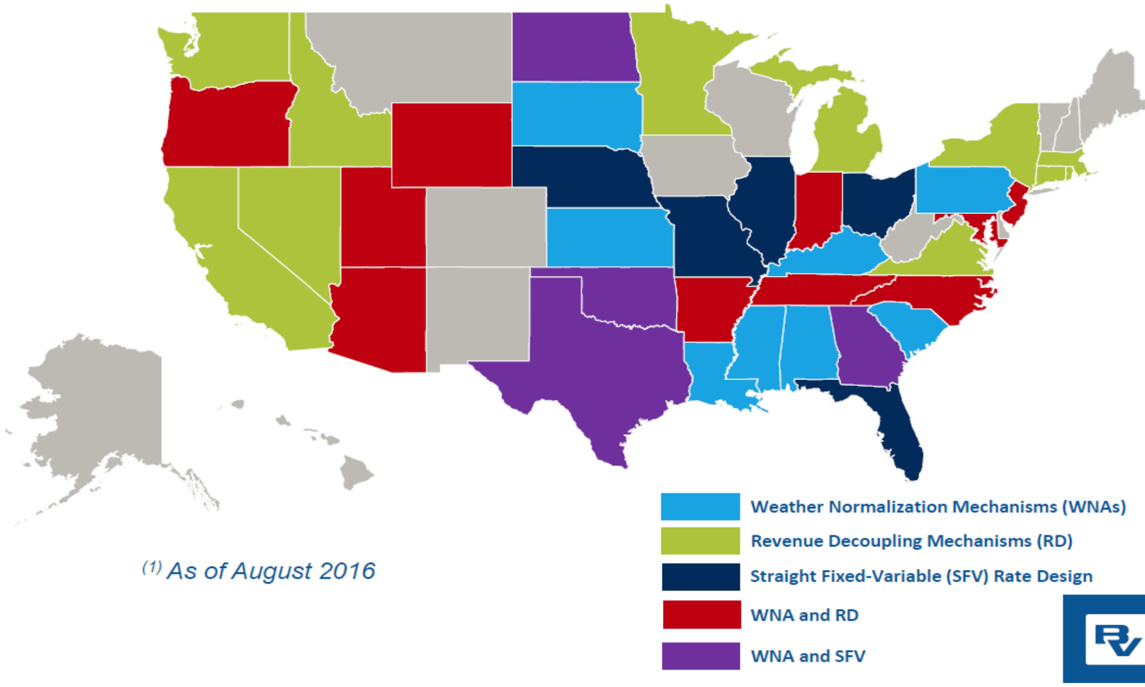


The resulting utility environment is one of significant change marked by escalating costs and declining gas usage – with such change being incompatible with the slower moving, historically cost-based traditional regulatory structure and process. Further, there has been a growing recognition that the ratemaking approaches of the past may not be working as intended, as evidenced by stakeholder impacts and original rate design objectives not being satisfied. As a result, this environment has made it much more difficult for gas utilities and their regulators to maintain the balance and integrity of the regulatory compact, with the inability to achieve just and reasonable rates using the ratemaking methods of the past and the creation of new financial stresses for gas utilities. Conversely, the alternative regulatory mechanisms required by industry changes attempt to protect and balance the regulatory compact in this new environment.

There are many needed changes to past utility ratemaking practices that requires a fundamental rebalancing of the regulatory compact. The traditional volumetric structure of a utility's base rates does not allow for the full recovery of a utility's non-gas cost of service approved by its utility regulator whenever a decline is experienced in the level of its billing determinates used to establish base rates. Rather, there should be a focus on ratemaking methods that enable the recovery of a gas utility's fixed costs through the fixed components of the rate structure. Further, the static nature of how a utility's revenue requirement is determined precludes the recognition and timely recovery of additional costs incurred by the utility in providing delivery service that is necessitated by unpredictable or uncontrollable business conditions that the utility has to accommodate. Rather, a test period determination for setting rates that reflect a better matching of a utility's revenues and cost should be used. Currently, different ratemaking treatment of volatile cost elements are not subject to meaningful control by the utility and that cannot reasonably be matched with corresponding revenues when rates are set only through a traditional rate case process. Rather, implementation of ratemaking methods that enable better tracking of such costs on a timely basis that are not administratively costly or burdensome to manage and review should be employed. The bottom line is that the gas utility industry requires ratemaking and regulatory solutions that address both revenue stability and revenue sufficiency.

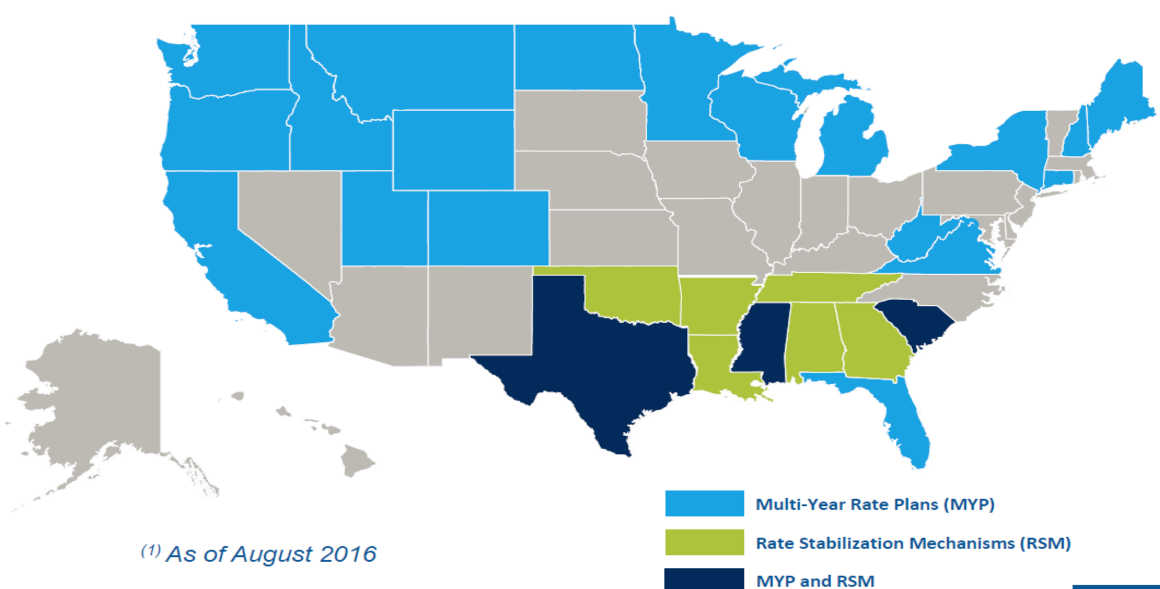
There are a number of ratemaking solutions being pursued, including individual ratemaking solutions for specific uncontrollable, variable, material, and recurring costs as well as comprehensive ratemaking solutions that address all relevant factors. Such individual ratemaking solutions include purchased gas adjustment (PGA) mechanisms that address changes in supply costs, rate design changes where customer charges more fully reflect fixed costs of providing delivery service, weather normalization adjustment (WNA) mechanisms, and revenue decoupling mechanisms. Other individual ratemaking solutions include rate adjustment mechanisms that address particular cost elements (e.g., energy efficiency program costs, environmental compliance costs, bad debt, pension expense), infrastructure cost recovery mechanisms for pipeline replacement and distribution system modernization, and innovative rates and mechanisms for serving unserved and underserved communities with natural gas. Comprehensive ratemaking solutions that address all relevant factors include adoption of a future test year, or step adjustments in multi-year rate plans, and rate stabilization mechanisms (RSMs). Use of such mechanisms may best be illustrated as follows:

REVENUE STABILITY RATEMAKING SOLUTIONS[1]



[1] As of August 2016

COMPREHENSIVE RATEMAKING SOLUTIONS [1]



[1] As of August 2016

In conclusion, enhancements are needed to modernize the regulatory process. More modern, comprehensive, timely, and efficient solutions are available and should be assessed to meet today's gas utility regulatory challenges. There should be a recognition by all parties that the regulatory process has become much more complex than in the past, especially with addition of one-off mechanisms necessary to address significant shortfalls of traditional ratemaking. Further, maintaining processes with all the significant changes and complexities has also led to a longer, more administratively burdensome regulatory process. Better paths forward exist and provide the proper level of regulatory scrutiny and accountability with benefits for both customers and utilities. We should provide the regulator, utility, and its stakeholders with the ability to operate within the regulatory process to address and resolve the utility's various ratemaking and regulatory issues in an efficient and cost-effective manner. This can be thought of as a "modernizing" of the existing regulatory process in order to lower costs to consumers and to ensure the financing and construction of the gas utility's necessary infrastructure investments.

5. Tom Tanton, Director of Science and Technology Assessment, Energy and Environment Legal Institute Introduction

Introduction

Thank you Mr. Chairman and members of the Committee for the opportunity to testify before you today on the important issues surrounding infrastructure investment and utility regulation. My name is Tom Tanton, and I am the Director of Science and Technology Assessment for the Energy and Environment Legal Institute. The Energy and Environment Legal Institute (E&E Legal) is a 501(c)(3) organization engaged in strategic litigation, policy research, and public education on important energy and environmental issues. E&E Legal advocates responsible resource development, sound science, respect for property rights, and a commitment to markets over government micromanagement.

By way of introduction, I have over 40 years of direct and responsible experience in energy technology and legislative interface, having been central to many of the critical legislative changes that enable technology choice and economic development at the state and federal level. Until 2000, I was Principal Policy Advisor with the California Energy Commission (CEC) in Sacramento, California. I began there in 1976, developing and implementing policies and legislation on energy issues of importance to California, the U.S., and international markets. These included electric restructuring, gasoline and natural gas supply and pricing, energy facility siting and permitting, environmental issues, power plant siting, technology development, and transportation. I completed the first assessment of environmental externalities used in regulatory settings. I held primary responsibility for comparative economic analysis, environmental assessment of new technologies, and the evaluation of alternatives under state and federal environmental law. As the General Manager at EPRI, from 2000 to 2003, I was responsible for the overall management and direction of collaborative research and development programs in electric generation technologies, integrating technology, market infrastructure, and public policy. From 2003 through 2007, I was Senior Fellow and Vice President of the Houston-based Institute for Energy Research.

As you consider changes to rate and other regulation in natural gas, water and electricity, keep in mind that all critical infrastructures, both those with rate regulation and those without, are increasingly interconnected and interdependent. The electricity infrastructure is dependent on and depended upon by natural gas infrastructure, while both are dependent upon and depended upon the information technology infrastructure, transportation infrastructure, and finance infrastructure. What you do will affect critical infrastructures beyond the particular industry of focus and will impact your overall economy and quality of life for all Missourians.

Your focus should include changing the charge to the regulator (Public Service Commission) in addition to easing the financial and business behavior of the regulated. This means setting metrics of success correctly (i.e., not picking technology winners and losers and ensuring appropriate social metrics). Be technology agnostic. If you want cheap, ask for cheap. If you want reliable, ask for reliable. If you want 'clean,' ask for clean and specify what it means. Do not assume a particular technology provides any of these things. Demand proof, you are after all the "Show-Me" state.

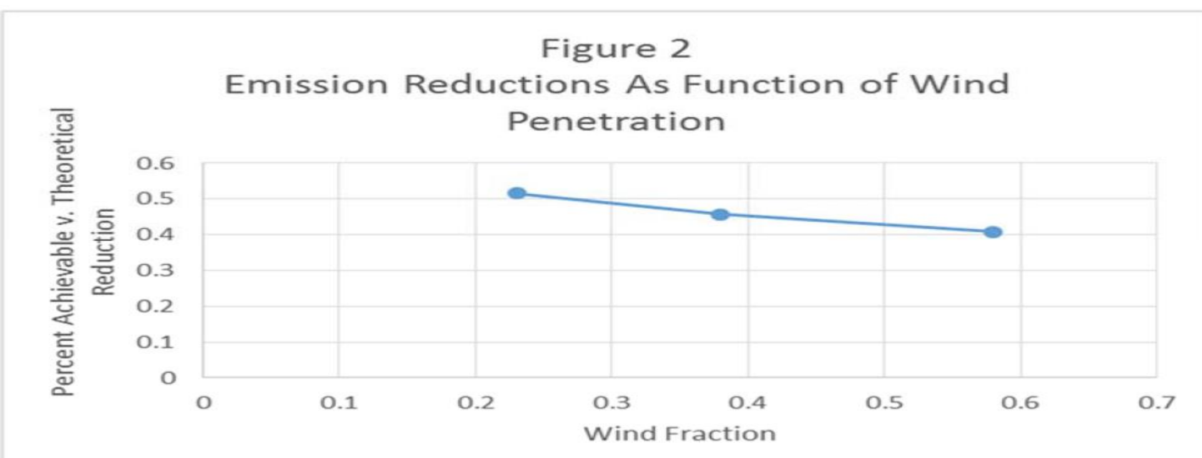
Too often analysts and policymakers place 'energy efficiency' on too high a pedestal. Energy, and its efficient use, is but one factor of production and not a primary one. Too often what is lost is productivity, which involves optimizing all factors of production including capital, labor, and land. You should direct the PSC to focus on overall economic productivity of capital, labor, and land, and ignore the siren call for energy efficiency, or worse, 'jobs created.'

The commodity of electricity is changing and along with it, regulation should change. Electricity is less and less a bulk commodity and is increasingly, from the consumers' perspective, a value added digital-enabling differentiated service. Rate regulation needs to shift from a cost of service basis to a value of service basis. Under the historical regulatory compact, utilities were granted exclusive access to a geographic area, in exchange for the obligation to serve those within the area and based on rates determined as the reasonable cost to serve. Today, some argue that elements of the rates should be priced based on their value to the customer, which often is different than the cost to the provider. But a mixed market, partially based on regulatorily determined costs and partially based on value, is likely to result in mixed market signals—even though it would be preferable to a faux market established by fiat. Reliability has different levels and different values depending upon the end use. Further, various quality metrics such as tighter voltage control and harmonics play an increasing role in consumer satisfaction and perceived value. Regulations should not only enable this but should encourage enhanced customer value decision points by differentiated end uses. Pricing options will need to expanded along with quality options, much like gasoline choices at the pump.

Building infrastructure takes time and careful management, just as does reforming rate regulation. Building in contingencies and autoresponse avoids the need to re-legislate a response to unintended results. The electricity crisis in California in 2000 was due, in large measure, to a wholesale bidding protocol that only works in supply surplus conditions and not, as we experienced, a supply shortfall; had there been in place a fall back bidding protocol we'd have saved perhaps $20 billion. At the same time a bit of grit can avoid overreaction; very short-term rate disruptions caused the whole approach to blow up and we ended up in a worse than we started. But California never actually deregulated nor had an energy crisis – it was a capacity crisis, initiated in the natural gas infrastructure. It has been unfairly used to denigrate the concept of deregulation.

Do not let your PSC rely exclusively on a so-called cost/benefit analysis to justify rate treatments. The non-linearity of costs and benefits, or the fallacy of composition, make questionable such analysis. For example, net metering may be good in small doses, but can become problematic in high concentrations; the problem is in setting rate components to get the right amount considering short- and long-term reliability. This requires analysis of distributional impacts in a way than allocates costs and benefits in an equitable (to participants and non-participants) fashion. Do not rely on estimates of aggregated benefits and costs. Fairness and equity, key to good public policy, requires consideration of the distribution of benefits and costs along with finding less expensive options.

The intermittent nature of some power sources, especially wind and solar photovoltaic, means that it is always necessary to have available other power sources capable of supplying and balancing the total peak load of electricity. Moreover, to avoid disruption in supply, these sources must be readily available, which means effectively that they are constantly spinning and consuming fuel. When solar output increases, generation companies curtail generation from other sources, known as “intermediate load units” sufficient to accommodate the solar power. When the solar output drops, generation from the intermediate load units is increased or otherwise brought back online as needed. The process by which generation is ramped up and down at a plant due to wind or any other factor is called “cycling.” Integrating erratic and unpredictable renewable resources with established coal and natural gas generation resources requires the electricity generators to cycle their intermediate load coal and natural gas fired units. This cycling results in significantly less efficient performance of EGUs powered by fossil fuels. The net result is increased emissions and fuel use, with attendant costs. These costs are seldom included in analyses of net metering. These costs increase, per kWh, at a rate faster than the growth in renewable generation. The curve of emission reductions per kWh versus wind penetration is downward sloping. While every grid is different and has different slopes and intercepts, Figure 2 illustrates this phenomenon using the Irish Grid. The vertical axis shows the percent reduction achieved compared to “perfect” substitution with full avoidance of fossil fuel for each KWh of wind. While differing in magnitude, the phenomenon holds for solar, but there is inadequate data to illustrate it given solar’s rapid and recent growth.



Source: ESB National Grid, 2004

Using cost/benefit analysis as the "be-all" is short sighted and often leads to poor policy. While necessary, it is insufficient. Use of cost/benefit alone ignores the equally important question of whether the benefits can be achieved at less cost. Are other techniques available that reduce carbon emissions, improve reliability, and lower pollution levels at an overall cost less than net metering? The answer is yes in each case.

The Midcontinent Independent System Operator (MISO) has analyzed various options to reduce carbon emissions in response to the Obama Administration's proposed Clean Power Plan. They compared the cost per ton of carbon reduced for a variety of generation and energy efficiency measures. They did not address NEM directly, but the results are still illustrative. The comparison of costs is shown in the figure, and illustrate that carbon can be reduced much more cheaply with easy operational changes like improving power plant heat rates or increased use of natural gas combined cycle than with most renewable technologies. The benefit of reducing carbon dioxide, and by extension NEM benefits, can most likely be achieved without resorting to the most expensive form of electricity generation, which at least for the time being is residential solar.

Reference case & Phase 1 scenarios

Scenario	EPA Assumptions and Methodology	Cost per ton of CO_2 reduction ($/ton) *
Reference Case	MISO's MTEP-15 Business As Usual future assumptions**	-
Building Block 1	In 2020, apply a 6% heat rate improvement to all the coal-fired units at a capital cost of $100/kW (amortized over 10 years).	5
Building Block 2	Calculate and enforce, starting in 2020, a minimum fuel burn for existing CC units to yield an annual 70% capacity factor.	53
Building Block 3	Calculate and add the equivalent amount of wind MWs to meet the incremental regional non-hydro renewable target.	237 Present value calculation for costs is the driver for the higher cost.
Building Block 4	Calculate the amount of energy savings for the MISO footprint and incorporate it as a 20-year EE program in the model.	70
All Building Blocks	Application of all building blocks.	60
CO_2 Constraint	Application of a mass-based CO_2 reduction target, allowing the model to optimize.	38

* The cost per ton of CO_2 reduction is indicative – actual values may vary depending on different input assumptions, etc.
** Assumptions matrix is available at https://www.misoenergy.org/Events/Pages/PAC20140820.aspx

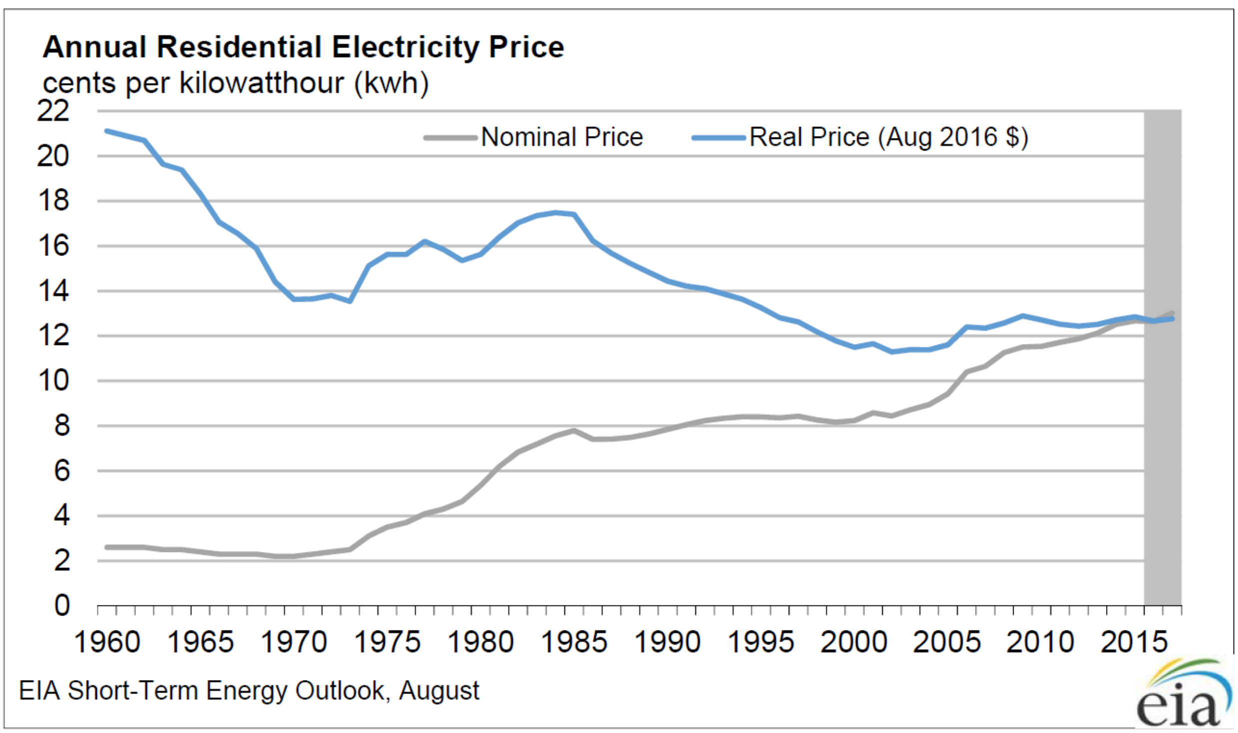
As a general principle, consumers should pay for what they get and get what they pay for. Reduce and eliminate cross subsidies or, at the very least, make them more transparent and explicit. This is nowhere more true than in the area of net metering. The electric power sector is critical infrastructure for the American economy. Electrification has been called one of the greatest engineering achievements of the 20th Century. Unlike most other industries, technological advances are unbundling production and delivery operations, rather than leading to vertical integration. Retail electric utilities remain regulated monopolies in every state. Retail electricity rates are not set by open markets, but result from ratemaking proceedings overseen by state regulators (e.g., public utility commissions or local authorities).

In many jurisdictions, laws or regulations require distribution utilities that sell retail electric power to customers to compensate customers for the power they generate, typically from solar

PV panels. Compensation can take the form of a reduction in a customer's bill if the customer consumes more electricity than he or she generates, or a payment from the utility if the customer generates more than he or she consumes. This creates a cross subsidy from non-net metering consumers to the net metering consumers, and is typically and highly regressive.

This raises the question of who the regulator should regulate. With net metering as an option for consumers, somebody (and I suggest it's your PSC) should be regulating the alternative-to-electric utility. Many advertising and sales pitches for solar net metering installations claim continued and consistent price increases for residential electricity. In reality, real prices for residential electricity have been remarkably stable, and have actually decreased since 1960, according to the Energy Information Administration (EIA). The following chart from the EIA shows that, in constant dollars, residential electricity has dropped from over 21 cents per kWh to under 13 cents per kWh, and there is plenty of reason to believe that trend will hold. Most observers expect future residential price increases to result primarily from proposed policies, like the EPA's so-called Clean Power Plan, that favors one technology over others, or effectively bans certain fuels like coal, not from market-driven changes and similar policies, like renewable portfolio standards, at the state level.

Solar sales pitches that rely on 'ever increasing electric utility costs' and similar deceptions, and eliminating inherent cross subsidies should be a focus of your PSC.



Finally, there is a blurring of the demarcation between wholesale and retail markets, which causes complexity in state versus federal regulation. This is perhaps most evident in states' renewable portfolio standards, fundamentally a retail consideration. Renewable requirements in the various states impose costs in other states by virtue of grid balancing in what is most often a multi-state grid. This raises the issue of federalism and the extent of states' rights. I have no specific recommendation for your legislature to provide guidance to your PSC other than to stay alert to possible encroachments on your own state sovereignty.

Thank you and I'm available for questions.

6. Eduardo Balbis, Accenture Utilities Strategy Practise Group*

Mr. Balbis testified that the state of Florida uses a projected test year, and have initiated step adjustments. Further, Florida uses four different trackers: a fuel adjustment clause, energy conservation cost recovery, environmental cost recovery, and nuclear development recovery. Further, Mr. Balbis testified that Florida also has a generation performance incentive factor that incentivizes plant efficiency, and an asset incentive that allows their utilities to optimize their portfolio for the customer's benefit. With an increase in severe weather, Florida also requires utilities to develop a storm hardening plan. Under this requirement, Florida Power and Light has spent $470 million annually on storm hardening. Florida Power and Light is a good example of infrastructure investment and holding down costs to consumers. Use of all of these mechanisms has resulted in relatively low costs to consumers at 10 cents per kWh, where Missouri is 12 cents per kWh.

Mr. Balbis also testified that customers are starting to expect the "Amazon" experience with their utility. He stated that the customer's top three desires are reliable delivery, a consistently reliable customer bill, and reliable customer service. However, many also have expectations about energy from their utility. For example, 66% of customers are interested in home energy devices, 60% are interested in electric vehicles, and 58% are interested in connected home products. These consumer trends are going to shift future energy demand. As a result, states will have to adopt policies that reflect this shift.

7. James Owen, Office of Public Counsel

The comments of the Office of Public Counsel (OPC) today are relatively broad and offered only as an opportunity to discuss a plethora of ideas with basic examples provided as a means of moving forward. Before moving forward, it is important to explain OPC is mandated by statute to represent the rate-paying public in matters before the Public Service Commission (Commission) as well as "other venues". We believe the Legislature falls under this broad definition, as OPC is hopeful this forum will serve as a starting point into a larger conversation where it can continually provide its relevant information on policy positions and proposed legislation.

Our comments are structured to address public statements made by legislators, policymakers, and investor-owned utilities (IOU) that the concept of "regulatory lag" is problematic in nature and must be fixed. The OPC respectfully disagrees with this. 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 rate cases that, in turn, have saved Missouri ratepayers tens of millions of dollars a year. Regardless, the OPC does have a number of potential fixes to the discovery and procedural rules of a rate case with the potential of shaving months off the process while still ensuring necessary and essential customer protections.

Further, the OPC encourages conversations about performance-based ratemaking as long as ratepayer protections are observed and codified. While OPC ultimately believes the current system is a proper, sufficient system of performance-based review of the utilities, we also recognize things can always be improved upon.

The OPC would also like to note states such as New York have set aside two-years of coordinated, facilitated dialogue to make sense of the changing regulatory landscape in an attempt to reach consensus. As our state is in a unique position of having this conversation right before Presidential and gubernatorial administrations change, now is the appropriate time to consider doing a rate case moratorium in order for this conversation to be paramount in stakeholders' minds.

I would also like to state our office has engaged in ongoing conversations with Christine Page at Missouri American Water Corporation and Tom Byrne at Ameren Missouri and have found these to be productive. We will continue to work these parties, and expand that circle when ideas start to fully form, prior to the legislative session commencing in January. But for now, these are the thoughts OPC would like for this body to contemplate.
As a general guiding principal, if one of the purposes of the Committee is to address regulatory lag, the OPC would request the legislators comprising this body pose the following questions to the regulated utilities for response:

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 return on equity (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 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?

<u>State of the Utilities in Missouri: The Need for Reform?</u>
Before entering a conversation about what law- and policy-makers can do about reforming the regulatory landscape, it is important to look at where we are. Currently, a reasonable observer would note investor-owned utilities are doing well here in Missouri. Consider the following:

<u>Ameren</u>: Ameren's second quarter earnings were $147 million, or $0.61 per share, unchanged from 2015. Core, or non-Generally Accepted Accounting Principles (GAAP) income, was also $0.61 per share, up from $0.58 in 2015. This reflects higher retail electric sales volumes driven by warmer early summer temperatures and infrastructure investments under Illinois' "modern, constructive regulatory frameworks", and show strong earnings despite the loss of Noranda Aluminum, the scheduled refueling outage at Callaway, and discontinuing the pursuit of a license for a second unit at Callaway. Warner Baxter said, "Our team continued to successfully execute all elements of our strategy…As a result of these solid earnings, I am pleased to report that we have raised our 2016 guidance to a range of $2.45 to $2.65 per share, up from our prior range of $2.40 to $2.60 per share." Ameren Missouri GAAP and core earnings for the quarter were $92 million, compared to $61 million and $104 million, respectively, last year. Influencing factors, other than those already cited, include the impacts of the 2015 energy efficiency plan (negative) and lower Operations & Maintenance (O&M) expenses (positive).

Great Plains Energy: GPE's second quarter earnings were $31.6 million, or $0.20 per share, down from $0.28 per share in 2015. However, adjusted (non-GAAP) earnings, which excludes expenses related to the Westar acquisition, were $85.6 million or $0.55 per share, compared to $0.28 per share in 2015. Terry Bassham said, "Our company delivered solid financial and operational performance for the quarter. We continue to optimize the performance of our business. Our generating units performed well during the extreme heat conditions that blanketed our region, where temperatures in June were the warmest since 1980." The company also remains on track to close the Westar acquisition in spring 2017.

Empire: Empire's net income for the second quarter was $9.2 million, or $0.21 per share, compared to $0.16 for 2Q15. Exclusive of merger costs, earnings are $0.27. Dividends per share remain unchanged at $0.26 per quarter. For the most recent twelve months, total earnings per share are $1.33, or $1.45 exclusive of merger costs, compared to $1.30 in the previous twelve months. Factors cited include: increased Missouri rates; lower O&M costs; mild winter weather; fuel decrease due to deferral timing; increased depreciation, amortization, and interest expenses. Brad Beecher said, "Our second quarter results, adjusted for weather and the merger-related costs incurred during the period, continue to meet our expectations…With FERC and Oklahoma approvals in place and a settlement agreement awaiting approval in Arkansas, we are making steady progress as we work through the remaining state and Federal regulatory processes necessary to close our merger with Algonquin Power and Utilities Corp. We continue to expect closing in the first quarter of 2017."

Regulatory Lag: The Concept, the Benefits, and How it Saves the Public Money

In utility ratemaking, there is an inherent time lag between when the utility makes new investments or increases its costs and when it recovers those costs in rates. "Regulatory lag" is due in part to the formal contested case processes used to review and approve rate cases and the complexity of the issues and volume of information prepared and under regulatory scrutiny. Moreover, in some states, rates are set based on historical costs and usage, not forecasted amounts. Using historical information increases the regulatory lag that occurs because utilities need to wait to prepare the filing until the historical costs are known. Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses. It also offers rewards for the inverse: companies can, for a time, keep the higher profits they reap from a superior performance and have to suffer the losses for a poor one.

Purportedly, there is consensus that excessive lag should be avoided as it can discourage needed investments and increase administrative costs. A number of states have instituted and explored approaches to limit regulatory lag in order to create an alternative regulatory process that encourages more investments. Putting aside the issue of whether more investment is always warranted, the Committee should be cognizant that increased exposure to potential stranded or imprudent assets necessitates that the risk be balanced between both shareholders and ratepayers. Consequently, many of the mechanisms designed to reduce regulatory lag should also equip the Commission with the power to Order refunds in the event that the utility collects more than just and reasonable rates would allow.[1]

Missouri currently has a statutory requirement known as the "file and suspend" method for rate case filings. Under Section 393.150 RSMo, the Commission can suspend the initial implementation of a requested rate change for a period of 120 days beyond the stated tariff effective date. If a hearing on the rate change request cannot be concluded within the initial period of suspension, the Commission may extend the time of suspension for a further period not exceeding six months. This traditionally has produced rate case proceedings of 11 months in Missouri. Upon a fifty-state survey, Missouri does incredibly well in turning these cases around.[2]

Missouri also utilizes a historical test year to set a normalized amount for cost and expenditures for the utility moving forward. Typically, an historical test year is the latest calendar year; however, a test year can be any prior twelve-month period of audited information. The presence of a statute requiring new capital expenditures to be in service and used and useful before they can be collected in rates, drives the need in part, to utilize a historical test year for Missouri.[3]

The combination of the "file and suspend method" as well as the requirement that capital expenditures be in service and used and useful before they are included in rates, leads to 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.[4] Regulatory lag can serve to make the utility more efficient and more prudent, as well as provide the utility with retained benefits from synergies.[5] 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, The "Economics of Regulation: Principles and Institutions", 48 (1989). In effect, regulatory lag creates the "quasi-competitive environment" that mimics how competitive firms operate and

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[1] 23 states permit refund of revenues based on shortened rate case timelines, interim rates, or rate adjustment mechanisms. See Attachment One, *State Regulatory and Statutory Practices Summary*.

[2] Regulatory Research Associates, Inc. form Joint response from Consumers Energy, DTE Energy, and MEGA from http://www.michigan.gov/documents/energy/Additional_Questions_4-6_response_from_DTE_Consumers_and_MEGA_420067_7.pdf.

[3] RSMo. §393.135.

[4] Kansas City Power and Light Request for a General Rate Increase, Case No. ER-2010-0356, Report and Order May 4, 2011.

[5] *Id.*

ensures natural monopolies are not abusing their power. If you believe in the competitive free market, you should support regulatory lag.

There is also the added, necessary benefit that this time will allow the Public Service Commission Staff (Staff), OPC, or other stakeholders, an opportunity to catch problems and concerns with rate cases with the potential of saving Missouri ratepayers from excessive costs for an essential service. As an example, the Empire Electric case (ER-2016-0023) was filed to include the capital costs of a generator - HRSG "Heat Recovery Steam Generator" converted Riverton 12 from combustion turbine generation to a more efficient combined cycle generation and added more capacity.

The Staff's direct case included an estimate of the capital costs of the HRSG because most of the costs had already been expended by Empire. However, the fuel costs included in Staff's direct case were estimated using the less efficient combustion turbines, i.e. fuel costs were higher than they would be with a combined cycle plant included. For this class cost-of-service study, Staff estimated the more efficient combined cycle would reduce fuel and purchased power costs net of off-system sales by $11 million.

Another example where Staff caught a significant issue due to the time allowed for discovery involved Missouri American Water Company ("MAWC") in their most recent rate case – WR-2015-0301. In that matter, Staff noticed a large amount of overtime incurred on MAWC's books during October of 2015. Staff learned this was the result of unusually high levels of premature failure rates associated with approximately 97,000 meters that had defective magnetic design or problems with other components of the meter resulting in either no recorded usage or lower-than-actual usage meter readings. Without this information, MAWC billed customers based on the prior year's usage.

As Staff did not learn of this until February of 2016, there was little time to adequately investigate the matter resulting in an investigatory docket opened to do so. It is the opinion of OPC that this significant issue would not have been caught by the Staff had an expedited rate case schedule been ordered. OPC offers these two cases as another example of why regulatory lag benefits not only the ratepayer but parties such as Staff as to allow them proper time to investigate all matters.

Also in the Empire rate case: PSC Staff found $3,082,367 in stopped depreciation from 2005 to present. This is money that was collected in rates but not booked to reserves because reserves exceeded the original cost of plant. Empire cited a Stipulation and Agreement from 1990 as its authoritative source for stopping the booking of the accrual.

Also, as a source of reference, Charles Hyneman – OPC's Chief Public Accountant – has compiled an exhibit to this document showing the most recent rate cases in regards to what the has sought vs. what they received. These savings were reached by an effort between that company, PSC Staff, our office, and the various intervenors who spotted problems with bookkeeping and calculations to reach what all parties could agree was the real value at issue.

This should also be stacked against concerns ratepayers – citizens – have brought forth to our office and to the Commission. While anecdotal, they do offer this Committee an idea of some of the other matters our office as well as the PSC Staff is able to investigate and deal with during our discovery process. It is important to remember that the reason we are here having this conversation is because we are talking about regulated "natural" monopolies. That means "ratepayers" or your constituents are a captive audience. There is no choice, therefore regulation and the associated regulatory lag serves as a proxy for the free market.

Allconnect complaint (EC-2014-0309): Pursuant to their agreement, KCP&L and GMO transfer certain callers and information to Allconnect (a telemarketing company). Allconnect pays a fee to KCP&L and GMO for every call transferred. "Staff and Public Counsel assert that KCP&L and GMO have violated the Commission's affiliate transaction rule by transferring customer information to Allconnect without having obtained the consent of those customers." (Report and Order, pp 17-18) "The Commission finds and concludes that KCP&L and GMO have made customer-specific information available to Allconnect without the consent of their customers in violation of 4 CSR 240-20.015(2)(C)." (Report and Order p 19) Order explained: "Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company shall immediately cease violating Commission Rule 4 CSR 240-20.015(2)(C)." Report and Order p 23. Order was issued on April 27th, and became effective May 27th. Despite the clear ruling that they violated the law, the companies continued to sell customer specific information to a telemarketer.

EC-2016-0001: "The complaint alleges that Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") failed to remove the Energy Efficiency Investment Charge ("charge") from the Dzhurinskiys' electric bill when the Dzhurinskiys received assistance on a utility bill that was not an Ameren Missouri bill. The complaint argues that such conduct violated Ameren Missouri's tariff ("tariff")." (Report and Order p. 1) The company initially opposed and hired outside counsel. This case was resolved by a stipulation and agreement where the tariff was modified to include a way for customers to verify eligibility for the program.

EA-2015-0146 (ATXI – an Ameren affiliate): Company's mistreatment of landowners at open houses held by the company became an issue discussed at the hearing and in the case. See ATXI reply brief, p. 22-25; Tr. Vol. 5. The Company argued that it did not need county assents to build the transmission lines.

GC-2014-0202:(Michael Stark, Complainant v. Summit Natural Gas of Missouri, Inc., Respondent) Company dug up landowners private road and put in a new line because they did not bother to look at maps. When the Complainant saw the contractor digging he told them to stop because it was his property. Company instructed the contractor to finish the work anyway. The Commission did nothing.

Consumer-Minded, Internal Reforms

With the use of such tools as update periods, true-up periods, and adjustments for "known and measurable" changes outside of the test year and true-up period, regulatory lag in Missouri has been greatly reduced. The aforementioned tools are all tools at the Commission's disposal and do not require legislative intervention.

When allowed to work as designed, regulatory lag provides the Commission with the ability to set rates that are fair, reasonable, and unbiased with no predetermined winners or losers.

Lag can also be reduced within the current statutory framework governing the Commission with modifications to its discovery rules. Below we will outline steps the Commission is able to take that would reduce regulatory lag. With many of the larger regulated utilities, there are a core set of common questions requested through the data request process. If these common set of questions were provided to the utility during the 60-day notification prior to the filing of a rate change request, then those responses would be provided as part of the initial application.

Discovery response periods for responding to data request can also be reduced to encourage quicker conclusion of the rate case proceeding. Currently under 4 CSR 240-2.090(2) (C), parties have twenty days initially to respond to a data request. Data request response time could be shortened to ten, twelve, or fourteen calendar days. Eliminating the requirement that parties have to come to the utility to view highly confidential or proprietary information without a showing by the utility of substantial risk of harm would also reduce time, as well as tax payer expense, to review the material.

Regulatory lag can also be reduced within the current statutory framework governing the Commission with modifications to the rules on testimony filings. Currently, IOU's file their direct testimony, then all other parties file their direct, then parties file rebuttal, and then parties file sur-rebuttal. In order to speed this process up, non-utility parties should be required to file their direct and their rebuttal testimony at the same time. This will move things along faster and lead to a decrease in repetitive filings as well as allowing issues to be joined earlier.

There are other modifications to the Commission's discovery rules which could eliminate delay in the rate case process should the Commission seek to revise those rules without any threat to ratepayer protection.

Further, the Commission should consider a two-step rate increase to cover expected post-order capital additions and identifiable expenses within a specified period of time, after audit to establish in-service date of capital additions and incurrence of identified expenses. 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.

Further, a change made internally for the Commission would be to allow parties in a rate case, complaint, *et al* to notice up motions for hearing rather than allowing this to be set by a regulatory law judge or by the Commission in some cases. The Commission could also create regulations that motions must be heard within a set period of time or establish a Commission version of "Law Day" where routine motions could be noticed up and heard. This would give power to the parties to move cases forward and expedite the litigation aspect of these cases.

Finally, it should be noted there is no central repository for data requests and responses whereby a party to this case can go and find material already requested. Parties routinely use rounds of data requests just asking for other responses to data requests. If these were all placed in one spot, that would not be necessary. Additionally, there's no requirement for companies to make certain material available in Jefferson City. PSC Staff members and OPC often have to drive to St. Louis, Kansas City, or Joplin to look at documents. This eats up time and money. If the PSC put this requirement in place, this would be helpful as well.

It should be emphasized 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 increases to offset this risk. In contrast, ratepayers have no such defense.

Many of the regulatory lag reduction mechanisms are already in place and available for both the Commission as well as the utility's use. Better yet, the Legislature would have to do nothing in order to enact these measures. It should also be noted IOU's already have a bevy of items that help with combatting regulatory lag as they see it. These include: AAOs, expense trackers, Fuel Adjustment Clause (FAC), Purchased Gas Adjustment (PGA), RESRAM, and the Gas ISRS

OPC would like to emphasize that context should be at the forefront in discussing any radical departure. Missouri is a vertically integrated state that has traditionally enjoyed lower electric rates than our deregulated counterparts.

Performance-Based Metrics

In the conversation circling the proposed electric legislation from the 2016 Legislative Session, there were references to performance-based ratemaking (PBR). While the OPC took the position the aforementioned legislation did not actually address PBR as it simply re-labeled formula ratemaking as such, we believe this is a subject worthy of more dialogue. 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. OPC has reviewed a number of states as well as the United Kingdom and found a number of ideas worth exploring within this process.

As a caveat, the following is offered by the OPC only as a point to begin conversation. Our intention is to continue revising our thoughts on the issue of adding additional performance-based ratemaking through this process and, as we learn more, may end up making additional recommendations as well as critiques of material we've outlined below. In the spirit of open dialogue, we are hopeful other interested parties will respect our efforts to participate in a dialogue and not view these thoughts as official OPC policy.

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."

A general consensus of the term “claw-back” is a provision that prevents unjust enrichment between ratepayers and the IOU’s. For the purposes of this discussion, such provisions could include audits that could be commenced by any interested party to be submitted to the Commission for review and applied as described above. This could include rate case moratoriums as what is often proscribed in New York State as a part of Agreements and Stipulations. Anything that triggers an immediate review rather than simply saying a party can “file a complaint.” This has proven an ineffective process for protecting Missouri ratepayers.

There are obvious concerns about manipulating data and information that should also be addressed in these regulations. Metrics could be redefined to exclude energy sold at a loss or energy from a unit that is operated out of merit order. This pitfall can be quickly remedied by ensuring that regulators carefully monitor how well performance incentive mechanisms are achieving their intended results, and step in quickly to make necessary adjustments, particularly where an incentive is clearly being gamed. In addition, the potential for gaming makes it all the more important that financial rewards and penalties are set conservatively in the beginning, and only increased once regulators and utilities gain experience with the performance incentive mechanism. Manipulation can be more difficult to detect, particularly when data are collected and analyzed by the utility. To reduce the risk of manipulation, verification methods should be adopted and independent third parties used to collect, analyze, and verify data where practical. Complex data analysis techniques should be avoided due to transparency issues. See *Utility Performance Incentive Mechanisms – A Handbook*, page 56.

According to the article “From Old to New: How Rethinking Regulation Can Deliver a Smarter Electricity System”, authors Sonia Aggarwal, Steve Kihm, and Ron Lehr outline five ideas that could transform regulation into a forward-looking system creating customer and societal value and that should be considered by this Commission moving forward:

1. Engage stakeholders to consider which customer and societal values are most important for the regulated electric sector, driving toward quantitative metrics for performance in each category. (This *Synapse* handbook found here and can be provided to the Commission upon Request as it is voluminous.);
2. Improve estimates of the utility cost of equity to reflect the minimum markup on money received from shareholders. This value should set the lower bound for the return on equity allowed to utilities;
3. Research the benefits in each of the value categories to estimate total benefits. This value should set an upper bound for the incentives offered to utilities that deliver these values;
4. Consider the difference between the cost of equity and the current return on equity. This is the money motivating shareholders and utility management, and represents the existing or baseline incentive for performance against which future incentives should be measured; and
5. Consider alternative ways to deliver the performance portion of utility revenues, aside from adjustments to rate of return, keeping in mind that direct shareholder incentives (or, better yet, “shared savings” programs where some incentive goes to shareholders and some flows back to the customer) may provide the most direct connection to intended performance.

Conclusion

The OPC believes there is great benefit to a continued conversation on improving electric regulatory matters through a combination of (1) tightening discovery and internal procedural rules; (2) modifying testimony schedules; (3) creating a two-step rate process; (4) creating a hybrid test year using historical and future rates; (5) adopting PBR measures with adequate consumer protections; and (6) asking substantial questions of all relevant stakeholders is a welcome place to start. Again, we would also urge lawmakers and policymakers to issue a moratorium on such cases until a new approach is finalized.

The OPC would like to finish with not our words but the words of some of the ratepayers – your constituents - who come to local public hearings we hold on rate cases. Our office remains hopeful their voices are also heard in this process. They do not get the luxury of government relation offices that can come here to represent them. They have our office and, more importantly, they have their elected representatives. Here is just a sample of what they have to say as attached.

ER-2014-0258 (Ameren Electric)

24 My question is: Do I go without heat
25 or do I go without medication?

Tr. Vol. 12, p. 19

19 may be would listen to it. As a utility user, and
20 I hope I am until I die, I don't like to spend
21 money on utilities from Laclede Gas, water, sewer,
22 anything. I think whatever I was paying for costs
23 that much, that's what I will pay. And I'm not
24 going in distress to pay this. But eventually
25 there's going to come a time in my life and in my
1 existence where I'm going to have to make the
2 choice; do I stay warm, do I eat, do I read, do I
3 flush my toilet, do I drink water? What's going on
4 here? And I won't be able to survive. Between the
5 fees and the costs, it's just becoming prohibitive
6 to live in this state, this country. Thank you
7 very much.

TR. Vol. 11, pp 49-50.

I've disconnected everything but the
13 refrigerator in my house. Because I'm going to see
14 how low my bill can go. My bill hasn't went
15 nowhere. I'm tired of being a little poor person
16 in the poor city paying to help the wealthy. So I
17 think UE should go back to how it used to be and
18 maybe some of these stockholders get off their
19 greedy A-S-S and have a apathetic heart because we
20 are our brothers' keepers. And try to do something
21 about it. That's all I have to say about this. I
22 was very upset because you live in a wealthy area,
23 I pay $48, get the hello out of here. And I'm
24 paying all this? So get it off the backs of the

poor. The stockholders, have an apathetic heart.

Tr. Vol. 11, p. 57

MS. JACKSON: Oh, let's see, I'm a total disabled veteran. I'm on a fixed income and the continual rate increases for Ameren exceed mine, and I'm sure many other people's, cost of living. And I would like to understand why they have continued to increase their rates every year, which exceed our increases every year, without the benefits coming back to us.

Since I am single, I have no children, then I don't qualify for any type of adjustments to my bill because apparently I don't spend enough because I don't have kids to spend it on.

Those -- I agree with what some of the other individuals have stated so I'm not going to reiterate all that again, I just wanted to be on record that not just seniors are struggling to pay these bills but the rest of veterans, disabled veterans, those of us that can't work, that aren't allowed to work.

Tr. Vol 3, p. 23-24

<u>GR-2014-0086 (Summit Gas)</u>

MS. WARNER: I want to agree with what Mr. Bartlett and Ms. Fisher stated. This is a community of single parents, elderly people, disabled people. I'm a caregiver for disabled people. It's a community of widows and widowers.

In the winter, you go into people's homes, and they have plastic taped over their windows and doors. It's also common to go into people's home, and they will ask you to step into a small bedroom because it's the only thing they're heating and they're heating it with a small space heater and they and their children are living in that little space.

People are going without food trying to keep their utilities on. Any increase in this community is devastating, any increase in utility costs is devastating. There is no room for people to take that money from.

I'm done.

Tr. Vol 8, pp.15-16 (Gallatin, MO – no commissioners attended)

<u>ER-2014-0370 (KCPL)</u>

MS. ATKINSON: I am a homeowner and a bill payer from the Blue Hills neighborhood. I am also a Parishioner at St. Therese Little Flower Church located in the Blue Hills community, and I work in the church as an Emergency Assistance Director.

Working with the families in this

community, I see many people struggling to pay their utility bills. I see people like Ms. Evan; she is disabled and receives $887 from Social Security Disability. She pays $300 in rent and she pays $75 a month in gas, $100 a month in lights, water bill of $100, and she already has an outstanding gas bill of $500. She pays co-pay for her medicines. She pays the telephone bill. She has to pay for food and other personal items. I told her about the rate increase proposal and the approximate cost it will entail and she nearly cried. This is just one family. I have three files drawers and more of stories similar to Ms. Evan's.

Tr. Vol 3, pp 17-18

Individual Testimony*
August 24, 2016

1. Natelle Dietrich, Staff Director, Missouri Public Service Commission

Good morning. My name is Natelle Dietrich and I am the Public Service Commission Staff Director. I'd like to thank the Committee for the opportunity to speak today. My comments will be focused on the current regulatory environment in Missouri.

The Commission is charged with ensuring utilities provide safe and adequate service at just and reasonable rates. In determining whether rates are just and reasonable, the Commission must balance the interests of the investor and the general public.

So, what is involved with determining just and reasonable rates? There are two main components – revenue requirement and rate design.

Revenue requirement is the cost of providing utility service. As you saw in the formula yesterday, revenue requirement is determined by a review of such things as capital structure, operating costs, depreciation, taxes, the gross valuation of property required for providing service and the associated accumulated depreciation on that investment, and an allowed return. It should be noted utilities in Missouri are allowed by law an opportunity to earn a return set by the Commission, but it is not a guarantee. The process of determining a revenue requirement involves extensive audit and review by Commission Staff of company books and records, and consideration of all relevant facts by the Commission. The Commission reviews information not only provided to it by the utility and Staff, but also all other parties that have intervened in the rate case.

Rate design refers to how the revenue requirement pie, or the cost of the service, is sliced among various customer classes. Cost causation – customers who cause the cost of providing service pay that cost in rates – is typically a driving factor, although many other factors such as rate shock to any one customer class and rate continuity are also considered. Depending on the utility, rate design can include such things as usage charges, customer charges, a demand charge, or energy charges.

These basic fundamentals of ratemaking have worked for 100 years, and the Missouri Supreme Court has said the Commission has no authority to "change the rate making scheme set up by the legislature." ***State ex rel. Utility Consumers Council of Missouri, Inc. v. Public Service Commission,*** 585 S.W.2d 41, 56 (Mo. banc 1979). However, there have been revisions over time, both through legislative changes and through Commission action within its general authority, to meet the changing regulatory environment. Examples include:

I. The Fuel Adjustment Charge (FAC). The FAC is designed to address the volatility of fuel and purchased power, as well as off-system sales. The FAC attempts to capture these costs in a more timely fashion. If costs decrease, the electric customer receives

* Written testimony is used in this report, unless none was provided. In such case, a summary of testimony is used and is indicated with an asterisk.

more timely benefit through lower rates. If costs increase, the electric utility can recover those costs more quickly.

II. Infrastructure System Replacement Surcharge (ISRS). The ISRS is designed to provide the utility company more timely recovery of a portion of the expenditures it incurs to replace and extend the useful life of its existing infrastructure. Most natural gas utilities have an ISRS, and Missouri American Water Company has an ISRS in St. Louis County.

Other adjustment mechanisms include the environmental cost recovery mechanism for electric and water utilities, and the renewable energy standard rate adjustment mechanism (RESRAM) and the Missouri Energy Efficiency Investment Act (MEEIA) mechanism for electric utilities.

As an example of Commission action addressing the current regulatory environment, in the current KCP&L Greater Missouri Operations Company rate case, the Commission ordered the ratemaking process to be concluded in 10 months instead of the traditional 11-month timeframe. The Missouri Commission has for many years used certain procedures, known as "true-up audits," that allow costs incurred well after the filing of a rate case to be audited and included in rates by the Commission. The Commission has also, in the past, authorized a straight-fixed variable rate, a form of decoupling, for some natural gas utilities, and has moved toward rate consolidation for utilities with multiple service territories. Finally, the Commission has authorized the use of the purchased gas adjustment (PGA). Similar to the FAC, the PGA allows natural gas utilities to recover the costs of fluctuating gas prices in a more timely manner.

The Commission has also periodically reviewed the regulatory environment. These reviews have included some of the suggestions you are receiving in this hearing process – accelerated discovery, enhanced reporting between rate cases, shortened processing timeframes. But due to differing interests and positions, many of the suggestions were opposed by one stakeholder type of another.

In June, the Commission opened a working docket to consider policies to improve electric utility regulation. Initial comments were received in July and responses to those comments were received on August 8. The Commission will host a workshop to further explore comments on September 13, and a Staff report is due October 17. We look forward to sharing information obtained as part of this docket with the Committee.

Many comments in the Commission's working docket addressed the concept of regulatory lag. Missouri rate cases are based on a historic test year. Generally, in order to be considered in rates, investments have to be "used and useful". Under Missouri law, compensation for "construction work in process" is prohibited for electric utilities. Thus, there is usually some amount of time between when a utility begins making a capital investment and when it may begin to recover that investment in rates, which is called regulatory lag.

Until fairly recently, regulatory lag operated to the benefit of utilities as they were in a "growth" environment with little additional investment. Now that we have shifted from a regulatory environment of growth to an environment promoting conservation with pressure for more investment, regulatory lag is often portrayed as a hindrance to investment.

It has often been asserted that regulatory lag can cause an electric utility to suffer prolonged under earnings (i.e., earnings below the level authorized by the Commission in the utility's most recent rate case) when it makes a significant plant investment to replace aging infrastructure or for other reasons. But these claims can be misleading, for several reasons.

First, while electric utilities are currently forbidden by statute to include the costs of electric plant under construction in rates before the plant asset is "in-service," Missouri utilities can capitalize a "carrying charge" on such facilities called the "allowance for funds used during construction," or AFUDC, during the construction period. The AFUDC charge has the effect of eventually fully compensating shareholders for their investment in utility construction projects by allowing the utility recovery of a deferred return on construction costs from ratepayers over the life of the asset in question.

Second, while the cost of new plant is an addition to utility rate base, this is offset in the rate base calculation by the amount of ongoing depreciation expense collected from customers relating to past plant in service additions. In other words, the two things are happening at the same time; the utility incurs the cost of new plant while earning depreciation on existing plant. The increase in utility depreciation expense collections over time, which is many millions of dollars annually for our large utilities, offers these companies the opportunity to make a commensurate amount of plant additions for infrastructure replacement or for other purposes without suffering any reduction to utility earnings.

Also, as you know, general rate case proceedings can take up to eleven months to complete in Missouri. However, the amount of regulatory lag that is incurred in respect to utility plant costs or expenses is generally much less than eleven months since procedures, known as "true-up audits," allow costs incurred well after the filing of a rate case to be audited and included in rates by the Commission. Under these procedures, the major categories of costs are updated to a point in time usually no more than five months prior to the effective date of rates for a utility. This procedure allows for the inclusion in rates of costs that have been subject to Commission audit and review, and yet also allows for rates to reflect a reasonably current utility cost of service.

The existence of regulatory lag means that utilities are unable to automatically update their rates to reflect changes in their cost of service, whether increasing or decreasing. In this same light, though, regulatory lag creates incentives for utilities to operate over time in the most productive and efficient way possible. A utility that reduces its costs over time will receive a reward by seeing its earnings increase because its rate revenues will not automatically decrease in proportion to its cost reductions. Conversely, a utility that is not able to control its costs effectively will as a result see its earnings reduced by the effects of regulatory lag, as its rate revenues will not automatically increase in proportion to its expenses. For this reason, initiatives with the purpose of eliminating or greatly reducing the amount of regulatory lag faced by utilities should be considered very carefully to avoid also eliminating the practical incentives Missouri utilities now have in place to encourage cost-effective and efficient operations.

As the Committee explores ways to address the current regulatory environment, it should be noted that not all state regulation is created equal. Missouri is a vertically integrated state. In other words, generation, transmission, and distribution are owned by a single electric firm.

Vertical integration typically has led to low-cost production and long-run efficiencies. In contrast, states such as Illinois have restructured or deregulated portions of their electric operations. Separate entities own generation, transmission and/or distribution allowing for wholesale competition.

The same thing is true with regulation. Several states have historic test years and audited rates such as Missouri, other states have employed decoupling, formula rates, or performance-based rate structures. But, even in the states with seemingly "like" regulation, there are different methods of determining rates. Some states allow forward-looking test years under varying circumstances. In states that have formula or performance-based rates most states allow for "sharing" of any utility over or under-earnings, and do not guarantee the utility a particular earnings result. In other words, one should proceed with caution when comparing Missouri regulations to those of other states.

As with any complex process, there are challenges. Missouri has aging infrastructure needs for all utility sectors. Environmental mandates have required large investments, which will likely continue into the next decade. According to the U.S. Energy Information Administration, Missouri ranks 25th in total energy consumed per capita. In 1997, Missouri ranked 32nd with an average annual electric rate of 7.8 cents per kWh compared to the national average of 8.4 cents. At the end of 2015, Missouri ranked 16th with an average residential electric rate of 10.99 cents per kWh compared to the national average of 12.67 cents. In the packets that were distributed, we have included some graphs and charts which compare Missouri rates to Illinois, Iowa, and Kansas. These were part of the Comprehensive State Energy Plan, and provide handwritten, updated numbers for year end 2014 and 2015.

Since 2000, the Commission has processed 23 natural gas rate requests, 27 electric rate requests, and 7 large water rate cases. The Commission recently finished rate cases for Missouri American Water Company and The Empire Electric District Company. It should be noted, some of these rate cases were statutorily required to maintain interim rate adjustments such as the FAC and the ISRS. In recent years, many contested issues, and even entire cases have settled through the settlement process discussed at length yesterday. KCP&L Greater Missouri Operations, Kansas City Power and Light, and Ameren Missouri have pending rate requests. The Office of the Public Counsel has filed an over-earnings complaint against Laclede Gas Company and Missouri Gas Energy. Staff is conducting an earnings investigation of Ameren Missouri's gas operations in conjunction with the electric rate case.

Details on the specific requests can be found in the packets that were circulated to the Committee.

Recognizing these challenges, the Commission is not opposed to change to the regulatory construct, but any change should be informed change that provides benefits to all stakeholders, and truly balances the myriad of interests that interconnect in very complex ways.

Discussions related to change should include asking the utilities – If there was change in ratemaking practices, what investment would you make that you cannot or will not make today under existing practices?

Instead of making sweeping changes, a more practical approach may be to provide the Commission with “more tools in its toolbox”. One option would be to allow the Commission the ability to utilize a decisional pre-approval process with post-construction review.

The Commission should retain its ability to balance the interests of the shareholder and the public, and allow the Commission to continue to audit the books and finances of each regulated utility.

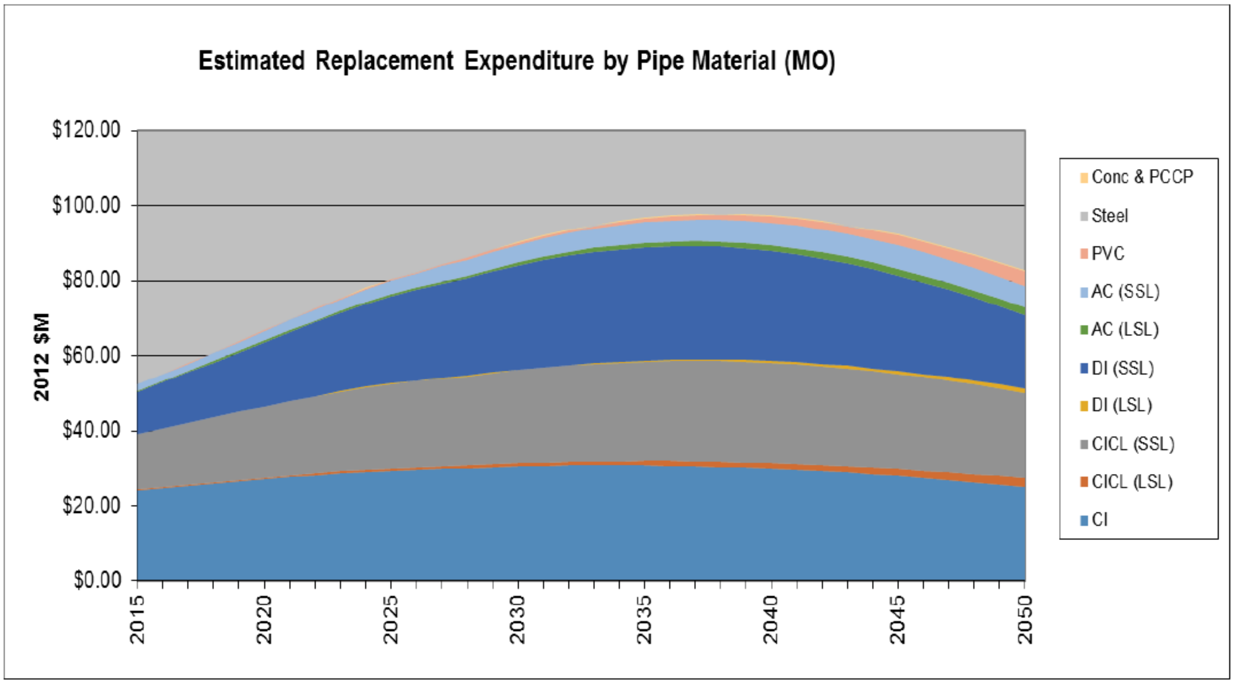
In short, the best approach to change would be to provide the Commission with flexibility to address the changing needs of the regulatory environment while continuing to maintain its core responsibilities of ensuring customers receive safe and adequate service at just and reasonable rates.

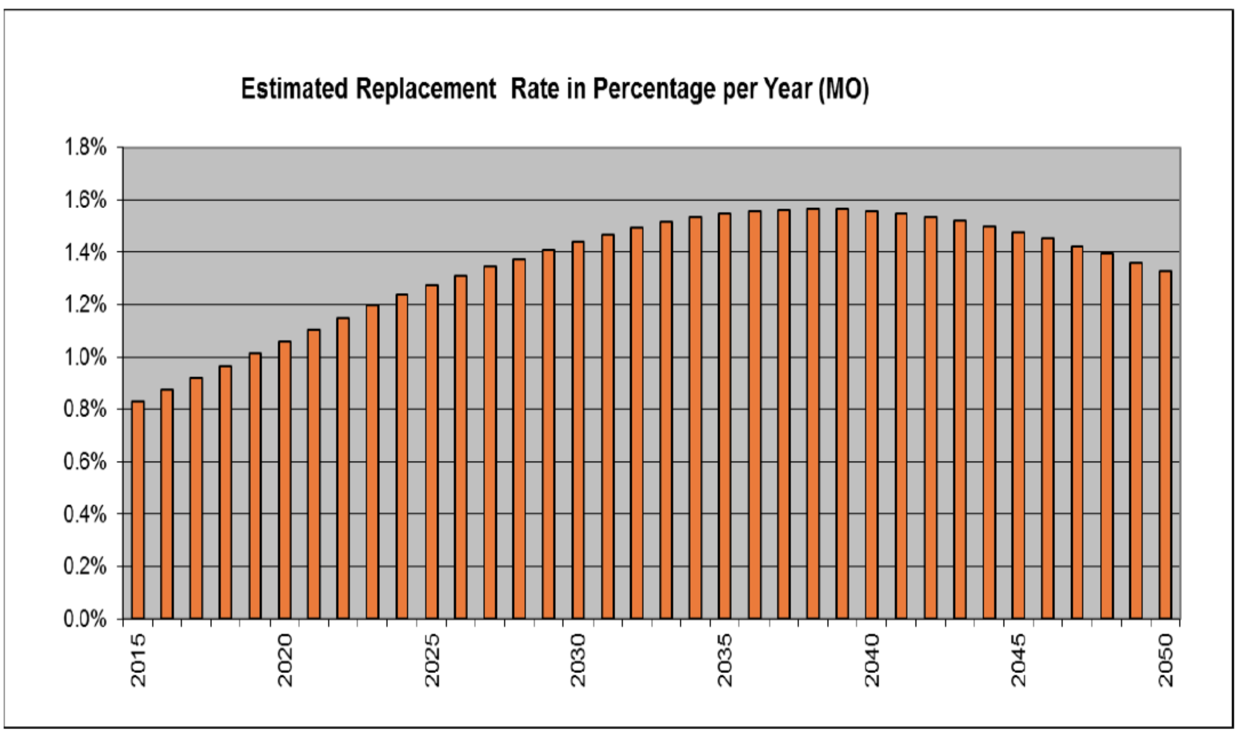
2. Edward Haye, VP and Chief Regulatory Counsel, American Water

American Water dates back to 1886 and is the largest water and wastewater services provider in the United States serving over 1,600 communities in 40 states and parts of Canada. Over 15 million people are served by American Water with 3.2 million regulated customers, 6400 employees, and 48,000 miles of pipeline. A map of our service area is as follows:

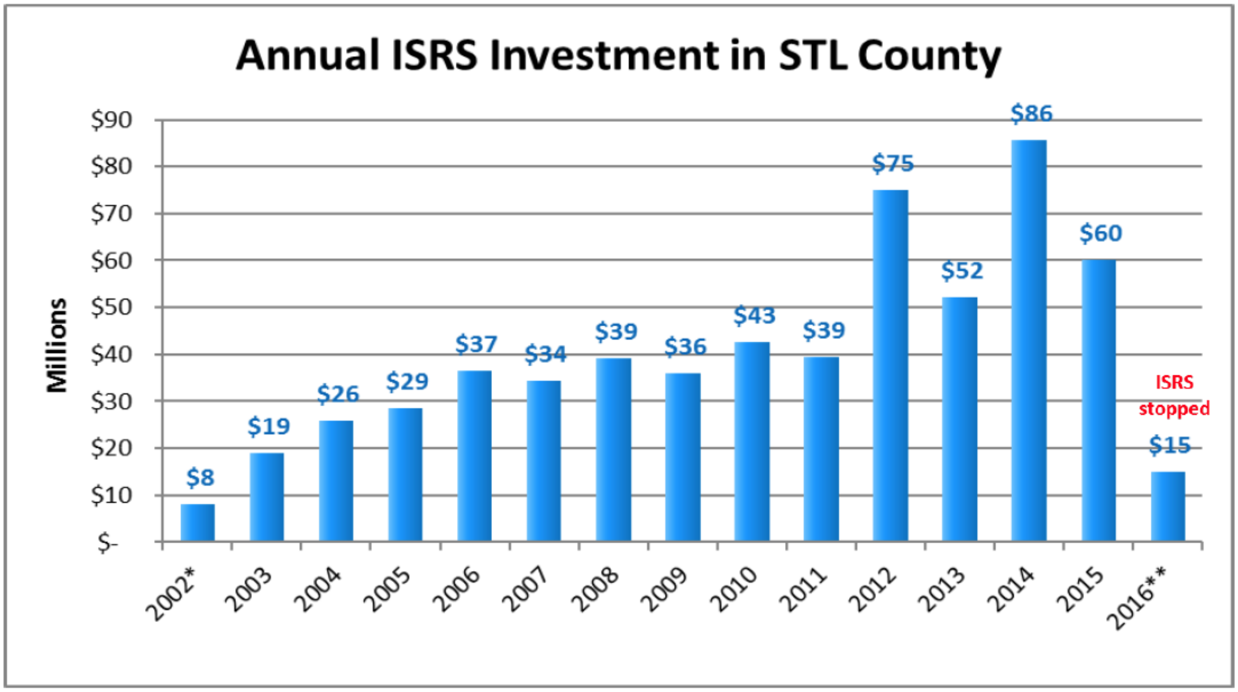
In addition to being the largest water utility in the United States, American Water is also the largest water utility in Missouri providing water and wastewater service to 1.5 million customers, or approximately 1 in 4 Missourians. A map of our service area in Missouri is as follows:

American Water is currently replacing slightly under 1% of its pipe material annually at a cost of nearly $50 million per year, but that is expected to dramatically increase in the next 30 years. These trends can best be illustrated by the following graphs:



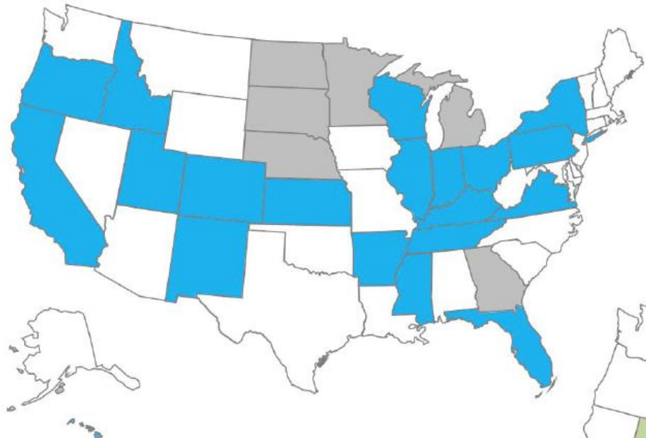


Investment to replace pipeline had been primarily financed through the Infrastructure System Replacement Surcharge (ISRS) mechanism in St. Louis County. However, a court challenged recently halted the ISRS, causing a massive drop off in investment and pipeline replacement as demonstrated by the following graph:



From our perspective, there are three primary ratemaking changes that would improve the Missouri regulatory process: ISRS, a forward test year, and a revenue stabilization mechanism (RSM). Water and wastewater utilities are the most capital intensive utilities when it comes to replacing infrastructure, but we are statutorily required to provide safe and reliable service, which is our minimal level of investment. This level of investment is far from our optimal level of investment. Further, the nature of water utility investment has changed from building infrastructure to serve new customers to replacing aging infrastructure. ISRS has, and could continue, to help accomplish this goal. Additionally, regulatory lag within the rate case process could be best reduced by a future or forward test year. Further, while most water costs are fixed, while most revenues are variable – which incents the water company to sell more water regardless of whether that is a good idea or not. This phenomenon is commonly referred to a “throughput incentive”. Under an RSM, water utilities could also promote water conservation and be guaranteed enough revenue for cost recovery. The following maps detail states policies that allow future test years and ISRS for water utilities and states that offer revenue decoupling mechanisms. Graphs and charts thereafter also demonstrate American Water’s throughput incentive and declined customer usage.

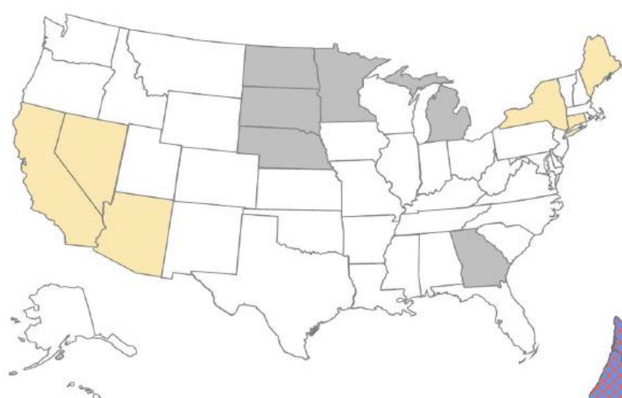
Future Test Years for Water



Infrastructure Surcharges for Water

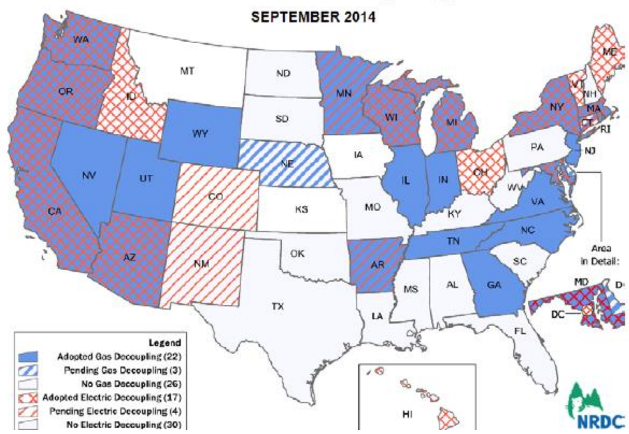
*Grey states do not regulate private water.

Water Decoupling in the US

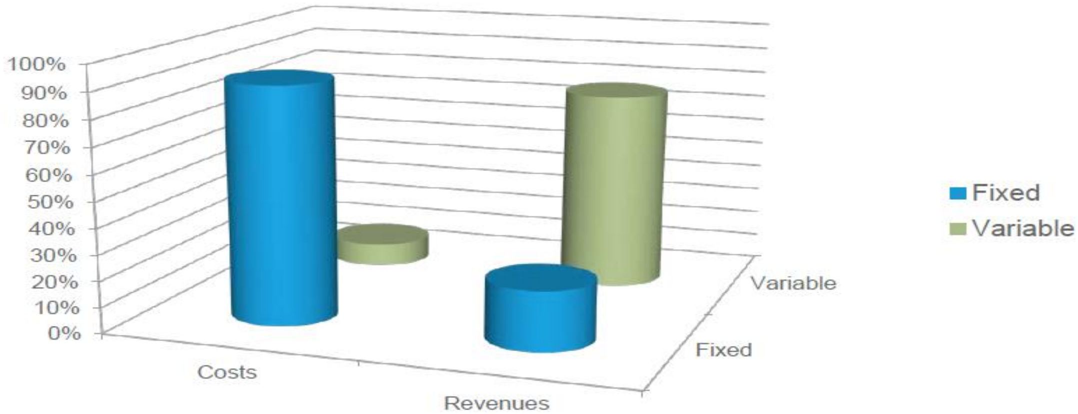


Gas and Electric Decoupling in the US

SEPTEMBER 2014

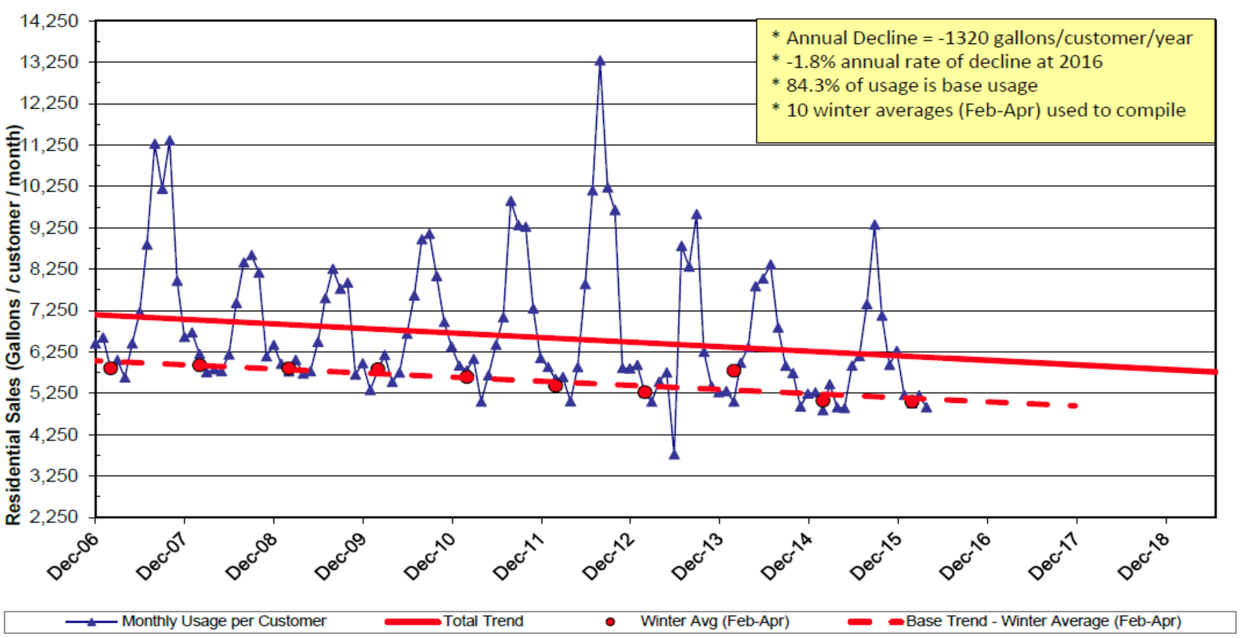


‹y states do not regulate private water.



	Costs	Revenues	Variance
Fixed	91%	23%	- 68%
Variable	9%	77%	+ 68%

Missouri-American Water
Residential Sales Per Customer (10 Year Trend)



3. Cynthia Marple, Marple Strategies

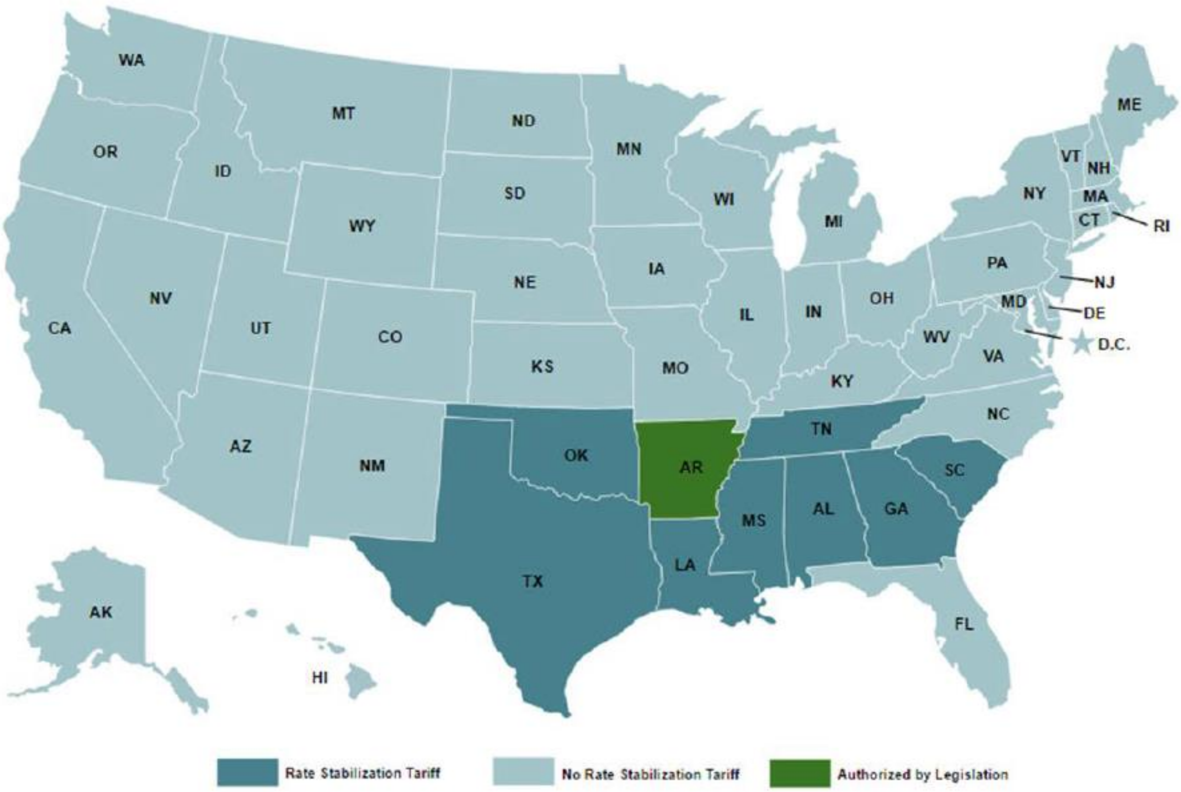
The gas industry is experiencing a rapidly changing environment of escalating and variable costs and declining usage. Such escalating and variable costs are largely due to the increasing number of infrastructure repairs and replacements necessary to maintain the safety and integrity of the system. Additionally, wages and material costs continue to rise, so cost recovery based upon historical test years consistently continues to under-recover costs. Further, uncontrollable, unexpected, and variable costs are also not sufficiently covered by traditional, historic cost based rates. Such delays in recovering large, upward swings in costs can impact a utility's financial health.

Gas utilities have also faced declining gas usage. Both customer and volume growth have been declining, largely due to changes in consumer habits with consumers purchasing more efficient appliances and better insulated homes. Additionally, weather patterns also severely impact consumption. Rates set on "normal" weather results in lower bills some years, and higher bills in others; meanwhile the costs for utilities is relatively fixed, resulting in over- or under-recovery of approved costs. As a result, revenues have been largely sporadic for natural gas utilities.

Consumers, legislators, and utilities have worked with their regulators to appropriately address such shortfalls through regulatory and ratemaking reforms not for the purpose of maximizing profits, but rather recovering prudently incurred costs. To address such issues, a number of alternative rate mechanisms have been "tacked on" to the historic, traditional rate structure in place for the last century including Purchased Gas Adjustment (PGA) clauses, revenue stability mechanisms such as straight fixed variable rates and decoupling, specific costs trackers for items such as energy efficiency and environmental regulations, infrastructure replacement riders such as ISRS, and main extension mechanisms for unserved or underserved areas. This has created a more complex, time-consuming, administratively burdensome and often contentious process to try to ensure all these parts work together as intended. More comprehensive solutions can provide benefits to customers, utilities and other stakeholders, with more timely, appropriate oversight of all relevant factors, while also structured to be more efficient and cost-effective.

Rate stabilization mechanisms (RSM's) are a superior way to comprehensively address changes to the natural gas utility environment. Rate stabilization mechanisms are adjustments to approve and authorize rates that actually stabilize cost recovery and rates. RSM is more comprehensive review of all relevant factors. Many consider rate stabilization the best of the innovative, non-volumetric rate designs because it adjusts both utility revenues and costs for changes that occur on an annual basis, while also providing benefits to customers, utilities, and regulators. This is primarily due to three reasons. First, RSM provides less volatile customer bills and reduces rate shock. Rate stabilization avoids rate shock with more frequent rate reviews that adjust rates on a more timely basis, rather than implementing infrequent, large rate changes all at once. Secondly, customer bills are further reduced as a result of lower financing costs. Timely recovery of costs reduces borrowing costs. Rates are reduced by a number of factors, including avoided cost of capital on deferred assets and reduced interest rates, among others. Third, changes in rates due to weather are timely. Weather normalization factors adjust for changes in volumes, so that customers do not pay too much in cold winters, like the Polar Vortex, and utilities can recover their largely fixed costs in warm winters. Fourth, the reduced costs of regulation lead to lower customer bills, which benefits all stakeholders. Traditional, fully litigated rate cases are lengthy and extremely costly. RSM proceedings are a more frequent, in-depth regulatory review of all relevant factors. As a result, they take less time and expend fewer resources. Fifth, energy conservation reduces customers' gas costs, which is about half of the customer's bill. Rate designs are included that remove the conservation disincentive, and encourage utilities to partner with conservation groups and help customers become more energy efficient and reduce their gas usage and commodity costs. Sixth, RSM provides incentives for cost reductions and efficiency improvements. This allows utilities to share a portion of the benefit from their cost reduction efforts – incentivizing cost management. This aligns interests between customers and utilities and encourages cost efficiency, which results in rates lower than would have otherwise been. Seventh, RSM allows for expedited infrastructure repair and replacement. RSM helps accelerate necessary utility investment to enhance safety and reliability of the critical infrastructure by allowing more efficient recovery of associated costs. Such activities also help improve operating efficiency and emission reduction. Eighth, RSM better matches costs and revenues by reducing regulatory lag. With less regulatory lag, a utility facing decreasing sales or increasing costs is in a better financial position. Revenue stabilization removes both the upside and the downside of regulatory lag, thereby making rates fairer and more equitable for both utility and the customer. Ninth, RSM incentivizes the utility for growth. With RSM, utility growth comes from new customers, not increased volumes of natural gas, so utilities remain committed to economic development within its franchise area. Revenues from customer growth helps lower rates and the utility's largely fixed costs are spread over a larger base, resulting in benefits for both customers and utilities. Tenth and finally, more frequent, in-depth regulatory reviews lead to a better understanding of utility operations. Annual examination of the utility's books leads to greater familiarity and expertise with the utility's books and operations. When the time arrives to hold rate reviews, staff is already well informed and familiar and does not need to start from scratch. The following map illustrates the states that have adopted RSM:

Rate Stabilization Mechanisms



Across the states adopting RSM, the average length of time RSM's have been in place is 12 years. 9 states have implemented gas RSM plans, including Alabama, Arkansas, Georgia, Louisiana, Mississippi, Oklahoma, South Carolina, Tennessee, and Texas. Further, at least 19 gas utilities have implemented or have pending RSM plans, including: Alabama Gas (AL), Atmos Energy, Louisiana Gas Service (LA), Trans Louisiana (LA), Atmos Energy Mississippi (MS), Atmos Energy Tennessee (TN), Atmos Energy Mid-Tex (TX), Atmos Energy Dallas Division (TX), CenterPoint Energy, CenterPoint Energy (AR) (pending –decision expected Sep 1, 2016), CenterPoint Energy Arkla (LA), CenterPoint Energy Entex (LA), CenterPoint Energy Mississippi (MS), CenterPoint Energy Oklahoma (OK), Entergy New Orleans (LA), Mobile Gas (AL), Liberty Utilities (GA), Oklahoma Natural Gas (OK), Piedmont Natural Gas (SC), South Carolina Gas and Electric (SC), and Willmut Gas (MS).

RSM works by operating with certain mechanics. First, RSM has both initiation and termination requirements. While most plans have no requirement to initiate the mechanism, some require a rate case to be concluded within the last 5 years. Companies may also exit RSM due to force majeure events and certain conditions, becoming subject to traditional ratemaking at that point. Second, key elements are reviewed for modification approximately every 5-6 years. Some plans have no defined review date, while the shortest term length is 3 years. Additionally, return on equity (ROE) may be fixed or annually adjusted during that time. Plans do not have to be modified, but as the business environment and company-specific situations change, there have been updates. Third, RSM operates by having an ongoing and timely review, with rates adjusted at least annually. More frequent, smaller changes are more predictable and easier to manage for both the utility and the customer. Cost are still subject to reasonableness and prudence under this model, and still include typical disallowances. Utilities are also required to provide schedules and work papers supporting the filing and adjustment calculation to the Commission. Commission staffs then review required filings and defined supporting documentation and request clarification or additional data as needed. Fourth, RSM caps annual rate adjustments. Rate adjustment caps are typically 3%-5% of the previous year's revenues. If plans are capped, sometimes excesses may be banked until the next year. Utilities are still allowed, outside of the cap, to make adjustments to address extraordinary changes. Fifth, RSM provides an earnings band around the authorized ROE ensuring a fair return. This removes both the upside and the downside of regulatory lag, thereby making rates fairer and more equitable for both utility and the customer. The band width typically is +/-1% around the ROE, with some more narrow. Many state RSM policies are symmetrical around the ROE, but a few states use an asymmetrical band. Under RSM, rate adjustments typically return the utility to the allowed ROE by the commission, but some plans also adjust rates to the edges of the earnings band. Sixth and finally, RSM commonly uses performance metrics and benchmarks as a basis for incentives. Customers benefit from enhanced business operations and lower costs, increased customer service and satisfaction, cost management, service reliability, and safety. Such metrics are often implemented as adders to ROE or as specific riders to address certain areas of focus. Some plans also allow the customer and company to share earnings above the ROE band, with a graduated scale that increases customers' share at higher levels.

In summary, the best ratemaking and regulatory reform of the last three decades is the rate stabilization mechanism because it is comprehensive. Other rate mechanisms that stabilize customer bills and utility revenues, like revenue decoupling and flat fee rates, when combined with cost trackers, have been successful across the United States. Flat fee and partially flat fee rate designs have moved Missouri rate design in the right direction. Missouri has implemented about half as many trackers as some states, but has implemented no revenue sufficiency or revenue adjustment mechanisms. Previous legislation allowed, but did not mandate, revenue stability and sufficiency measures, and Missouri regulation has lagged behind in this measure. Investors and rating agencies compare and contrast states, and Missouri is behind in the eyes of many in the investing and debt rating communities. Implementing a comprehensive modern rate structure like RSM by statute would be the best thing for Missouri stakeholders – customers, utilities, and the state.

4. David K. Owens, Executive Vice President of Business Operations and Regulatory Affiars, Edison Electric Institute

I am David K. Owens, Executive Vice President of Business Operations and Regulatory Affairs for the Edison Electric Institute. (EEI). EEI is the trade association that represents all of the nation's investor-owned electric utilities. I am honored to speak with you today about alternative ratemaking approaches to address the rapid changes in our society that are impacting utilities and the importance of providing customers clean, safe, reliable, and affordable energy. I will also talk about renewable energy, the evolution of the electric grid, and the importance of refining approaches to net energy metering.

It is an understatement to say that utilities are in a rapidly changing environment. They are in a period of transformation. Much of the change is stimulated by policymakers who are seeking to have the utility reduce its carbon footprint. At the state level, this involves the use of renewable portfolio standards, and there is an array of federal initiatives such as the Environmental Protection Agency's Clean Power Plan. Greater energy efficiency is strongly encouraged through demand-side management programs, stricter building codes, and appliance standards. Many customers have sustainability goals, and are seeking green tariffs and power supply sources other than the increasingly clean portfolio of utilities. Moreover, some customers are providing their own generation through private solar, and utilities must purchase energy from these distributed generation sources at regulated rates.

Technology is also driving change. Nationwide, over 65 million smart meters have been installed which enable two-way communication between the utility and customers. Advanced metering infrastructure and other smart grid technologies are a part of grid modernization aimed at improving reliability and resiliency, and facilitating the integration of distributed resources including intermittent renewables. Time of use and prices based upon location of resources can encourage customers to use the grid more efficiently.

And finally, change is occurring because of increased concern about reliability, resiliency, and cybersecurity, particularly as it relates to the power grid. Grid modernization involves replacing old infrastructure, adding new technologies to enhance reliability, and digitizing the grid through monitors, sensors, and automated controls.

Alternative Ratemaking

These changes are having a substantial impact on utilities. Growth in demand for traditional utility services has slowed; it is flat in many regions and increasing penetration of customer-owned distributed generation is creating new challenges for utilities. Capital expenditures programs must address the need for clean energy. A smarter, modernized grid to better serve customers, and replacement of aging infrastructure by adding new facilities does not trigger sales growth. New approaches must be developed to meet changing customer needs and expectations. This involves more customized solutions including special arrangements with customers such as green tariffs, but much more is needed in the regulatory area.

Traditional regulation cannot adequately address many of today's challenges. Base rates that compensate utilities for costs of non-energy impacts are adjusted only in general rate cases with historical test years. Historical test years cannot capture rapid changes in costs. Future test years can. Moreover, most base rates are drawn from volumetric and other usage charges but the cost of base rate impacts is driven more by capacity (infrastructure costs) than system use in the short-run (energy). So when sales decline, there is a smaller contribution to the capacity or infrastructure costs. Utilities needing to make capital expenditures are compelled to file rate cases more frequently. This was not a problem with increased customer usage because the resulting incremental revenues helped utilities finance rising costs without rate cases.

Alternative approaches to regulation are being proposed in many jurisdictions to address these challenges. They include: formula rates, multi-year rate plans, and fully-forecasted test years that may involve significant regulatory changes. Less sweeping approaches such as revenue decoupling and cost trackers address more targeted challenges. These alternative ratemaking approaches enable utilities to address the signficant challenges before the industry, while at the same time making the necessary capital expenditures to provide customers with clean, safe, reliable, and affordable energy.

Net Energy Metering (NEM)

There is a growing interest in the use of distrubted generation (DG) systems, such as customer-owned and leased rooftop solar photovoltaic (PV) panels, to meet electric power needs. DG offers an attractive option for some customers, and utilities are actively examining the ways in which DG systems can work with, and enhance, the existing electric power grid.

However, such renewable technologies are variable, which means they do not produce electricity when the sun is not shining and the wind is not blowing. To ensure around-the-clock reliability, they need to be backed up and balanced with non-renewable power plants.

As solar technologies become increasingly popular, solar PV costs continue to decline. The cost of generating solar power has declined by half since 1998. Moreover, universal (utility-scale) solar is about half of the cost of private (rooftop) solar, and wind-powered energy generated on land is often far less costly than this. Universal solar projects are highly efficient because they are designed to follow the sun to maximize electricity production and are located in the sunniest areas. Because they capture more of the sun’s energy, they reduce the carbon footprint more substantially than rooftop solar facilities.

Although costs keep declining, the price differential between private and universal solar will remain.

It is important to note that private solar and other distributed technologies are being subsidized through extensive federal and state tax credits and other incentives. They also benefit from regulatory policies, such as state net energy metering policies, which were approved to encourage the introduction of these systems and technologies when they first came to market years ago and were very costly.

Net energy metering enables ratepayer funded subsidies that many states are reevaluating for many reasons. It promotes the most expensive form of solar energy, at the least-cost: it creates winners and losers among utility customers.

Net energy metering is a billing system which credits the private solar or other distrubted systems the full electric rate for any electricity they generate and they can sell this electricity to their local electric company via the electric grid. Electric companies are required to buy this power at regulated rates.

Finally, consumer protection is an increasing area of focus, and must continue to be a priority to address consumer complaints about fraud and misrepresentation on the part of solar leasing companies.

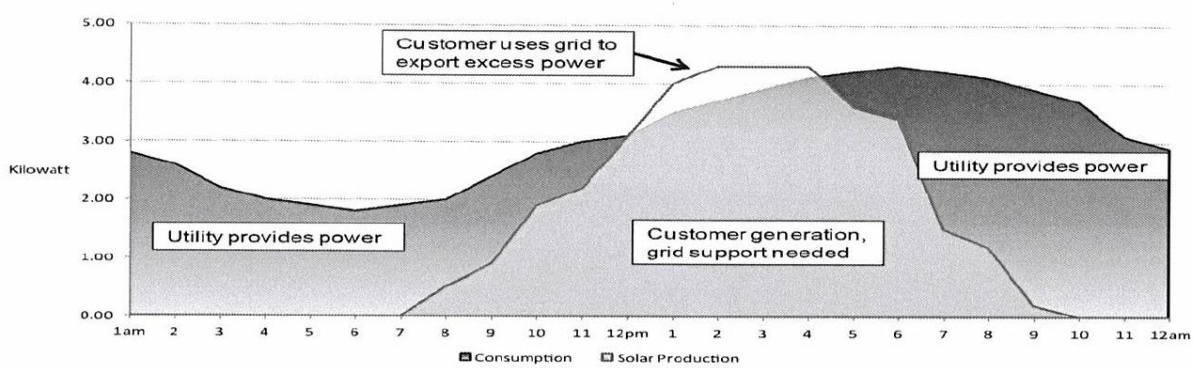
The Value of the Grid

There is a common misconception that DG customers derive no benefit from being connected to the host utility's distribution systems. While it is easy to say that a DG customer is "free from the grid," that is simply not true – even a for a DG customer (or a microgrid) that produces the exact amount of energy that it consumes on any given day or other time interval.

Figure 1 shows that because private solar facilities are variable, they are not available 24/7. Private solar facilities must remain interconnected to the grid at all times. Even at peak output, rooftop solar systems need the support of the grid to start large motors like air conditioners and refrigerators. Energy storage could be helpful in meeting consumer needs, but large batteries are still expensive and do not last long enough. Thus, even battery backup requires connection to, and services from, the grid.

FIGURE 1

Typical Energy Production and Consumption with Rooftop Solar



Source: *Value of the Grid to DG Customers*, Institute for Electric Innovation, October 2013.

Moreover, installing rooftop solar does not reduce grid investment needs. Since solar generation peaks in the middle of the day whlie power use peaks in early evening and because of the need for back-up power at night and when it rains, snows, or is cloudy, the grid must still be sized to meet peak needs.

The grid is increasingly becoming a multi-directional network interconnecting millions of consuming devices and flexible distributed energy resources including DG. The grid delivers new and exciting technologies to improve our lives and to help consumers better manage their energy use through smart technologies including distributed solar and demand response.

Private solar systems are part of this change because they transform a utility's distribution system from a one-way delivery mode into a complext network, but their electricity flows need to be carefully monitored and balanced. High penetration of DG actually requires electric utilities to invest in new systems to assure that the grid remains safe, reliable, and resilient.

Operations of such a system also require greater situational visibility, as well as collaborations with consumers and energy services providers. This also requires major new investments in monitors, sensors, and automated controls. But most distributed solar is not dispatchable, and is therefore of less value than larger systems that can be controlled by grid operators.

That's why it's important to make sure that public policies recognize the value of the grid to all customers, both those with and those without distributed generation.

Recent studies have raised concerns about the cost-shifting issues surrounding net energy metering that gives DG customers a bill credit for their solar production. This shifts the costs to pay fo the grid from DG rooftop solar customers to non-DG customers, including the low-income and elderly populations.

I am pleased that many states are examining this important issues to refine net energy metering policies and to end cost shifting. The National Association of Regulatory Utility Commissioners (NARUC) also supports the need to address this issue in its Draft NARUC Manual on Distributed Energy Resources Compensation, issued on July 23, 2016. The manual recognizes that industry developments such as technology advancements and growth in distributed generation have exposed deficiencies in the standard non-dynamic, volumetric residential rate designs that most utilities offer customers. Current flat and largely volumetric residential rates do not sufficiently reflect time-differentiation in underlying resource costs, the peak demand-driven nature of infrastructure investments that rates are intended to reocver, or the 24/7 use of the power grid by distributed energy resources. A range of approaches are discussed in the manual which are being considered by states which are all aimed at addressing the cost shift to non-DG customers to ensure that electric rates are fair and reasonable for everyone and that everyone who uses the grid continues to share in the costs of paying for the grid.

Since January 2014, many electric companies have sought approval from their respective commissions to increase residential (or fixed) charges to recover costs associated with the distribution grid to address the cost shift issue.

Some states are examining proposals for redesigning residential rates. They have concluded that existing tariffs do not reflect the underlying cost structure for providing electric service and maintaining grid reliability and resiliency. These are typically two-part rate designs. The first part is based on fixed costs incurred by the utility to serve the customer (e.g. like metering, billing, poles). The second part is based on a volumetric change based on a customer's monthly electricity consumption. Fuel costs would fall into this category.

Some options for evolving residential rates to meet changing customer needs and expectations include: introducing a demand charge, increasing the fixed charge, grid access charges, minimum bills, time of use rates, dynamic pricing, and stand-alone service class rates.

The introduction of a demand charge would change the rate structure from two-part to three-part – fixed charge, volumetric charge, and demand charge. Careful consideration of these alternative rate designs are a part of the dialogue at NARUC addressing the integration of distributed resources and the evolving distribution system. In fact, at the recent summer meetings at NARUC, two sessions were exclusively devoted to this area.

Another important issue is fuel diversity. Maintaining a diverse and flexible power supply is critical to a strong local and U.S. economy. At the same time we must invest in electric transmission and natural gas pipelines to assist the development, integration, and use of zero-emitting or low-carbon-emitting power supply sources such as renewables, nuclear, and natural gas facilities.

Conclusion

In closing, alternative regulatory approaches are needed to address the significant changes in our society which are impacting utilities' abilities to provide clean, safe, reliable, and affordable energy to customers. Power supply sources must be cleaner and greener. The grid must be modernized so that it is the platform for new and evolving technologies to meet and exceed customer needs and expectations, and rates must provide for the capital expenditures to make this happen. It is recognized that solar and other renewables are an important part of out nation's current and future energy mix. Customers should have the option to install private solar panels and sell the excess electricity they generate based on fair and competitively determined prices.

Also, I believe that it is critical to have collaborative forums and proceedings such as this one, to discuss and understand the issues to help shape future policies.

Thank you for the opportunity to speak to you today. I look forward to your questions.

5. Erin O'Connell-Diaz, Former Illinois Commerce Commissioner

Good Morning. My name is Erin O'Connell-Diaz, and I am a veteran state public utility regulator. I have spent over 30 years as a public servant, 13 years as a Judge, and two terms as a Commissioner at the Illinois' Commerce Commission. It is a pleasure to be back to testify before your Committee regarding changes that Missouri is contemplating for its electric utilities recovery metholodogy. As you consider this important issue, it may be helpful to keep in mind certain factors that Illinois was experiencing before we adopted performance-based ratemaking regulations contained in our historic Energy Infrastructure Modernization Act (EIMA) reforms in 2011. As I shared with you this past spring, we in Illinois have found that in a short period of time, this legislation is delivering real and quanitifiable benefits to our citizens. As the same time our rates have remained low and stable, electric reliability is award winning, and we are building a secure energy future for our state. I would reiterate that prior to my state's adoption of performance-based ratemaking, several factors motivated the changes that occurred in Illinois. I would suggest Missouri is encountering those same obstacles that will impede its path to the future without changes to its regulatory model.

In Illinois, we recognized that traditional ratemaking was not doing a good job of promoting the utility service attributes that customers and state policymakers care most about, such as rate stability, reliability, customer service, energy efficiency, enabling renewable and distributed generation development, and economic development, as well as productivity improvements. Clearly, the 120-plus year old traditional regulatory process utilized in Illinois was in need of streamlining; rate cases had become frequent, numerous adjustment mechanisms, riders and deferral accounts had significantly complicated the process, and it had become highly adversarial and costsly for all parties to participate. The results of the proceedings were unpredictable, volatile, and incomprehensible for most consumers. The time had come to devleop a comprehensive solution as a more productive alternative.

Through many iterations at the legislature and with input from many stakeholders, the Illinois legislature passed EIMA, which provided for a new process to develop performance-based rates (PBR) through electric utility rate proceedings while still maintaining the Illinois Commerce Commission's oversight and authority. The Commission retained its authority to ensure rates are just and reasonable and based only on prudently incurred costs, and parties retained the right to file for appeal of a Commission Order. In fact, the Commission exercises its historic authority in these cases that the utilities are required to file on an annual basis. This process, now in its fifth year, allows for better alignment of interests between customers and the utility; places the emphsis on performance, not just the cost building blocks that add up to a utility's revenue requirement; and provides an equitable division of the benefits of performance improvement and cost management. Without implementation of PBR, Illinois' electric system would have been at risk of under investment and overall customer dissatisfaction. PBR is a proactive solution that can provide sustained benefits for all utility stakeholders and that takes a longer-term perspective on the balancing of interests and establishment of utility service that is in the public interest.

I appreciate the due dilligence that you and your colleagues are going through as you consider this change. I admit that I was skeptical when we first started looking at making these changes to our regulatory model. However, we are five years out since we implemented the changes and we now have an abundance of evidence that clearly shows this was the correct path. In particular:

- Illinois' residential and industrial electric rates remain the lowest in the Midwest Region as well as some of the lowest in the United States; our rates have risen less than Missouri's (for the distribution portion of a customer's bill an average of 2.5% increase in the last 4 years) while at the same time the dynamic transformation of our electric grid is taking place and currently delivering benefits to all sectors. Low prices, new build, better and greener services to industrial and residential customers, job creation, and customer-centered service are all occurring under the watchful ee of the public utility regulators. To be clear, this legislation has been truly tranformative for our state as a whole;
- Regulatory oversight by the public utility regultory commission has been enhanced with annual rate filings requiring review and approval of the yearly costs through fully litigated proceedings open to all stakeholders. As a Commissioner, a big concern was that we not lose that important role. Extensive and timely annual Commission review under PBR is a critical component of the process and one of the pillars of its success. In fact, in your proposed legislation, your Public Service Commission would enjoy more discretion than is afforded under the Illinois legislation. Also, the prudence standard of review by

the Commission, that ensures just and reasonable rates, remains intact and unchanged under this legislation;

- PBR allows the Commission, its Staff, and other parties to have a timely and discrete annual review of all costs resulting in less time and overall rate case expense, which benefits everyone;
- Transparent and measurable performance metrics are required of utilities with penalties for non-compliance, as well as strong consumer protection provisions – again, Commission oversight is at work;
- Illinois was just rated 2nd in the nation for grid modernization and our state is benefitting from record reliability improvements resulting in millions of dollars saved by consumers. Since 2012, we have experienced the following societal savings in our two regions: Ameren Illinois - $228 million; Commonwealth Edison - $3.1 billion;
- 4,800 jobs have been created statewide, not including indirect supply chain employment opportunities. Robust programs have been implemented that bring together consumer advocates, educational sectors, and many community organizations as critical partners in building Illinois' energy future;
- Modern grid technology has been deployed system-wide, such as smart meters, modern distribution and transmission components, energy efficient/green improvements, and the grid has been better secured against storms and cyberattacks;
- Utilities have been enabled to make much needed long-term investments to modernize the electric grid at the same time ensuring customers realize the benefits of these improvements; and
- Credit ratings of the utilities have been kept sound during times of accelerated investments in the system which in turn keep construction costs and debt service costs lower, thereby benefitting all.

Indeed, other regulatory mechanisms may seem to be able to provide for the appropriate acceleration of investment to modernize Missouri's grid. However, I would caution that those options may appear adequate but in operation could serve to hamper your goal of actually achieving balanced and comprehensive grid modernization. In Illinois, we had various trackers, riders, and other financing mechanisms provided for in our rules. What we discovered was that none of those regulatory plans permitted, nor enabled, the type of holistic and large-scale, long-term planning necessary to achieve meaningful and comprehensive grid modernization and deliver 21st Century benefits to our consumers. Most importantly, we recognized that our state's enabling legislation had to change in order for the Commission to be able to legally implement such all-encompassing energy infrastructure building programs.

I know that you, your colleagues, and your Public Service Commission have the best interests for the future of Missouri at heart. I can tell you that of all the programs that I was involved with in my 30 years of public service, my participating in the implementation of PBR is one of my proudest accomplishments. It has allowed a reality of growth and forward movement for my state in a manner that I did not think possible. It is my firm belief that all the attributes I referenced above simply would not have happened if we had not changed the channel to PBR regulation.

In closing, I appreciate the thought and consideration you each have given to the many sides to this issue. Given our experience with PBR, you and your colleagues can be assured it is not an untried idea but a regulatory model that is transformative and works in both traditional and deregulated states. This legislation is currently allowing Illinois utility customers to be participants in the 21st Century by leveraging a modernized utility foundation with new technologies, services, and customer benefits that are the value streams of tomorrow. I believe that PBR mechanisms are important tools for regulators and utilities. Each state has unique needs, the the type of PBR mechanism or other regulatory changes that are instituted to address Missouri's need for electric grid modernization will benefit from your discussions and stakeholder input. This collaboration hopefully will result in the formulation of a plan that will hold utilities accountable, provide real and quantifiable benefits for the customers they serve, and culminate in the creation of a 21st Century energy backbone for current and future generations of Missouri citizens.

6. Kristy Manning, Director, Division of Energy

The public utility regulatory model developed in the early 20th century was premised on the belief that a single vertically integrated electric utility was the most economic means of providing electricity to the public. Under this model, a natural monopoly investing in large, long-lived generation assets and selling as much electricity as possible to the greatest number of people was thought to minimize the per unit cost of electricity production and delivery.

More recently, some of the economies of scale underlying the monopoly provision of production and distribution have eroded and growth in new customers has declined. Over the past few decades, significant technological advances and innovation have occurred in energy services and equipment. Rate increases outpacing wage growth, and an increased awareness of the health and environmental impacts associated with heavy reliance and dependence on fossil fuels, have led to customer demand for greater control over how much electricity they consume as well as cleaner and more autonomous sources of energy. Early adopters are already investing in energy efficiency and deploying distributed generation. The resulting stagnant load growth, coupled with increasing costs to the utility, has resulted in a continuing cycle of frequent rate case filings by electric utilities in order to preserve their opportunity to earn an adequate return on investment.

The Comprehensive State Energy Plan (CSEP) recognized that in order to ensure energy reliability and affordability, Missouri's energy supply must be diverse and secure, and its usage must be efficient. In addition to utility progress in these areas, customer access to reliable, clean and affordable energy plays an important role in increasing diversity and security.[1] The Plan provides insight into the potential for job creation and economic development, as well as the impact of energy activities on our environment, and offers a series of next steps and recommendations for action designed to meet Missouri's short- and long term needs. Implementing the recommendations will help the state create more 21stt century jobs, grow our

[1] Missouri Public Service Commission Case No. EW-2016-0313, *In the Matter of a Working Case to Consider Policies to Improve Electric Utility Regulation*, Department of Economic Development – Division of Energy: Policy Recommendations to Address Electric Utility Regulatory Challenges (DE Comments), July 8, 2016, page 1.

economy, improve the reliability and resilience of our energy systems, and keep utility bills affordable.[1]

However, to realize the above stated goals, the historical relationships between utilities, customers, and regulators must be reshaped. Under such circumstances, utility cost recovery should be based less on the level of sales and more on facilitating and strengthening consumers' access to, and participation in, energy efficiency, renewable energy, and distributed generation deployment.

In the absence of meaningful reform, customers will continue to reduce the amount of electricity which they buy from electric companies, requiring utility rates to increase to recover the fixed costs of providing electricity over a smaller volume of sales. In spite of these technological and economic changes, the electrical grid will remain a fundamental part of our state and national infrastructure that must be maintained.

Facilitating electric utilities' ability to offer new technologies and services will also allow the integrity of the electricity grid to be maintained, assuring its place as a reliable, fundamental piece of our national infrastructure and thereby spurring economic growth, creating jobs, and providing electricity to those who continue to rely on it for basic service. As electric utility costs continue to rise and prices for technologies such as distributed energy and energy storage continue to fall, it is becoming more economically feasible for customers to produce a portion, if not all, of their own electricity needs. To retain value to such customers, utilities may need to offer new and more advanced services.[2]

The Division certainly recognizes the external pressures Missouri utilities are experiencing including state and federal policies, environmental compliance and regulation, and consumer demands for more services all while needing to control costs and ensure reliability. Even without compliance mandates, the increasingly competitive pricing of renewable energy systems and resources and greater availability of more efficient equipment, appliances and measures is resulting in flat or declining utility sales.

Additionally, as the Department of Economic Development (DED) and the Division of Energy (DE) work with local economic development agencies to attract and retain businesses, companies and site selectors are quite interested in understanding the market for and availability of renewable energy resources. Even existing Missouri companies such as General Mills, General Motors, Kellogg's, Nestlé, Procter & Gamble, Target, and Unilever have expressed interested in gaining increased access to clean energy.[3] The CSEP also discussed the desire of companies to, "… expand businesses' access to long-term, fixed-price renewable energy that is

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[1] Missouri Department of Economic Development – Division of Energy. 2015. "Missouri Comprehensive State Energy Plan – Executive Summary", page 2.
https://energy.mo.gov/energy/docs/Executive%20Summary_FINAL_10.05.2015.pdf

[2] DE comments, page 3.

[3] Missouri Public Service Commission Case No. EA-2016-0358, *In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing it to Construct, Own, Operate, Control, Manage, Operate and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood-Montgomery 345kV Transmission Line*, Direct Testimony of Michael P. Skelly on Behalf of Grain Belt Express Clean Line LLC, June 30, 2016, Schedule MPS-2.

cost competitive and that helps reduce energy emissions beyond the companies' business as usual."[1] Companies should work with their electric utilities and other interested stakeholders to facilitate reaching agreements or making arrangements.

Grid Modernization and Investment

Current regulation provides for the recovery of costs associated with grid modernization projects, primarily targeted towards improving reliability and operating efficiencies in centralized generation and delivery infrastructure. It's less focused on meeting customer demand for emerging technologies and leveraging demand-side resources as a beneficial and cost-effective alternative for offsetting future needs for supply-side resources. Lag of recovery creates a significant barrier to large investments in new technology, modernization and diversification of grid resources.

Providing a targeted mechanism for accelerated modernization and diversification of grid resources can enhance the ability to meet customer demand for emerging technologies, promote energy services sector growth, transition to more decentralized and cleaner forms of energy, and leverage demand-side resources as beneficial and cost-effective alternatives to supply-side resources. Additionally, improved two-way communication across the grid would benefit customers by empowering them to make or opt into cost savings decisions and benefit utilities and energy services providers by generating opportunities for growth.

As an example, the Missouri Energy Efficiency Investment Act (MEEIA) passed by the Legislature in 2009 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. A properly designed program to encourage grid development can benefit all stakeholders. Missouri's citizens will benefit from economic growth spurred by increased development of demand-side energy resources, lower long-run energy costs, improved health outcomes from reduced emissions, and increased availability of enhanced energy services can result in lower future bills for all rate-payers. Utilities will benefit by aligning their interests with customers' interests through improved incentives for accelerated grid modernization. Utilities also benefit through reduced cost of meeting future energy needs and environmental compliance. Participants in the energy services sector, including contractors, third-party service providers, ancillary product providers, researchers, and emerging technology developers can benefit from new markets in energy management tools and solutions, energy efficiency products, distributed generation, and renewable energy resource development.[2]

Integration and Innovation

Innovation such as higher integration of energy efficiency and demand response, load shaping, localized production of energy (and associated transmission and distribution benefits and efficiencies), microgrids, and integration of EVs would contribute to portfolio diversification, increased system optimization, and enhance resiliency and reliability. As such, specific policies and technologies should be considered as part of grid modernization efforts in Missouri.

[1] CSEP, page 178. https://energy.mo.gov/energy/docs/MCSEP.pdf

[2] DE comments, pages 9-10.

Electric Vehicles (EVs)
The role of EVs and their related service equipment (EVSE) in addressing electric utility regulation policies should also be considered. EV adoption should be recognized as a way to increase utility revenues (decreasing utility rates across all customer classes) and provide suppliers with an avenue to develop more charging infrastructure. Furthermore, with EV owners primarily charging at home, charging can be programmed to occur when the grid is underutilized based on time-differentiated rates that reflect the lower cost of off-peak energy use. Such initiatives would create not only a new revenue stream from which utility companies could recover infrastructure costs, but unlock the ability for a diverse consumer base to enter the EV market as well.

Alabama Power provides rebates for both residential customers' purchases of EVs and commercial customers' installation of EV infrastructure. Illinois provides rebates for EV 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 EV infrastructure development.

As there are increasing concerns with regard to emissions, greater deployment of EVs on Missouri roads will lead to greater reductions in greenhouse gas emissions in-state. EVs emit roughly six pounds of carbon dioxide while a conventional gasoline-powered vehicle produces roughly 50 pounds of carbon dioxide at the tailpipe for the same trip. Even with Missouri's current generation portfolio, purely battery-powered EVs result in the decreased emission of over 3,000 pounds of carbon dioxide per year than conventional vehicles.[1]

Missouri Energy Efficiency Investment Act (MEEIA) Enhancement
As of May 2016, 25 states had either "stand-alone" energy efficiency mandates or allow energy efficiency as part of their renewable portfolio standards.[2] Missouri ranked 31st in per capita spending on electric energy efficiency programs in 2014, outranked by many states which currently have electric energy efficiency mandates; per capita spending in Missouri was well below the US median.[3] The CSEP notes that while MEEIA serves as a good first step in the platform for achieving significant levels of energy efficiency, there are opportunities for policy modifications that would encourage more aggressive and mandatory targets and should explore the inclusion of social and environmental benefits in cost-effectiveness testing.

Alternative Financial Instruments for Customers
In order to eliminate the capital barrier to energy efficiency implementation, regulated utilities should be encouraged to offer on-bill financing programs, which provide a convenient way for consumers to obtain financing for energy efficient improvements that provide cost-effective energy savings. On-bill financing would benefit consumers by reducing their immediate energy

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[1] Ibid, pages 20-22.
[2] American Council for an Energy-Efficient Economy. 2016. "State Energy Efficiency Resource Standards (EERS)." Page 1. http://aceee.org/sites/default/files/eers-052016.pdf
[3] Gilleo, Annie, Nowak, Seth, Kelly, Meegan, Vaidyanathan, Shruti, Shoemaker, Mary, Chittum, Anna, and Bailey, Tyler. 2015. "The 2015 State Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy. Report U1509. Page 122. http://aceee.org/sites/default/files/publications/researchreports/u1509.pdf

burdens and increasing their disposable incomes and utilities would benefit from demand reductions associated with energy efficiency savings. On-bill financing could also spur economic development in areas served by regulated utilities through job creation and consumer savings. Laclede Gas (Spire) in Missouri offers it as well as Kansas, Connecticut, Hawaii, Illinois, and New Hampshire.[1]

Microgrids

A microgrid is a system in which a small-scale electrical grid exists with its own power system that can operate separate from, or alongside, the central utility power station and manage the flow of generated and consumed electricity. Microgrids provide increased reliability, sustainability, and resiliency in emergency situations and can integrate management of thermal and electrical load for increased efficiency. Microgrids also contribute to local economies by utilizing local energy sources, including renewables (wind, solar, geothermal, and biomass). Additionally, microgrids satisfy increasing customer demand for a greater role in how and where their energy is generated.[2]

Net Metering and Easy Connection Act

Missouri's net metering act sets limits for the capacities of customer-owned renewable distributed energy resources which may be connected to utility grids. This limit can act as a barrier to the adoption of larger systems, such as those of corporate customers, by requiring the separate negotiation of interconnection terms for those systems. The statute also does not explicitly allow for virtual net metering, aggregated net metering, and third-party resource ownership, which represent opportunities to better leverage additional projects and financing. Additionally, the statute does not describe how CHP and microgrids should be treated, as it is specific to renewable distributed energy resources; this leaves ambiguity in the treatment of CHP, and does not answer questions about interconnecting microgrids with multiple distributed energy resources. Additional eligible resources could be included, specifically, biogas and landfill gas renewable energy systems.[3]

Renewable Energy Standard

Much like MEEIA, the RES represented a significant accomplishment following its ratification by voters. Renewable energy costs have also declined significantly in recent years, and public interest in renewable energy – along with regulatory drivers – has continued to increase. While Missouri utilities are beginning to embrace the transition to renewable energy, some parties oppose this development. As 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.[4]

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[1] DE Comments, page 20.
[2] Ibid, pages 22-23.
[3] Ibid, page 19.
[4] DE Comments, pages 18-19.

Nontraditional Rate Recovery Tools
The Legislature authorized the PSC to approve non- traditional cost-recovery mechanisms to address specific policy objectives or immediate needs to allow for the recovery of capital costs and expenses, either by tracking them as they are incurred between rate cases (i.e., accounting authority orders, or "AAOs") or on an expedited basis (i.e., trackers). PSC has authorized AAOs and trackers associated with Infrastructure safety inspections, replacing infrastructure damaged by ice storms and tornadoes. An AAO was also utilized as an alternative cost recovery approach for Iatan II.

When properly implemented, such mechanisms allow for focused cost recovery on an expedited basis and can encourage needed investments in infrastructure. The CSEP identifies trackers and balancing accounts as the most common mechanisms being used by states to facilitate grid modernization.[1]

Rate Case Timing
The Commission already has broad discretion to grant interim rate relief but no electric utility has sought interim rate relief since 2010. The PSC could consider setting standards for the processing and evaluation of interim rate relief cases to provide utilities and other stakeholders additional transparency and certainty on how those requests would be processed and evaluated. It also already has flexibility to address targeted incentives, an opportunity which should be preserved. For example, the Commission has considered and approved the sharing of off-system sales and capacity release revenues, as well as hedging plans, in past utility cases.[2]

Revenue Decoupling
Decoupling is designed to make utilities indifferent to energy efficiency, distributed generation, and other reductions in customer usage by allowing utility shareholders to continue earning a return on their investments regardless of usage changes. Numerous states already allow some form of decoupling. Rate adjustments in these states have typically been within two percent above or below the retail rate.

Limited decoupling is already authorized to an extent under MEEIA, which allows electric utilities to recoup revenues lost from the implementation of demand-side programs and natural gas utilities are allowed to use decoupling mechanisms to account for weather variations and energy efficiency, though the statutory provision authorizing these mechanisms has not been used to date. Additional forms of revenue decoupling for electric utilities (e.g.., full decoupling or decoupling to account for weather) would require statutory authorization.

However, it should be noted that policies such as PBR and decoupling are not sufficient enough policies alone to effectively encourage efficiency investments. ACEEE has found that a combination of incentive mechanisms (e.g., decoupling) and requirements to meet efficiency targets leads to the achievement of higher levels of efficiency savings. Any appropriately

[1] Missouri Public Service Commission Case No. EW-2016-0313, *In the Matter of a Working Case to Consider Policies to Improve Electric Utility Regulation*, Department of Economic Development – Division of Energy: Response to Comments Addressing Electric Utility Regulatory Challenges (DE Reply Comments), August 8, 2016, page 6.
[2] DE Comments, pages 7-8.

designed policies allowing for decoupling or PBR should be accompanied by a requirement for utilities to achieve all cost-effective demand-side savings, as well as other robust assurances of benefits to customers, prudence reviews, and (if needed) customer refunds for over-collections.[1]

<u>Performance Based Rates</u>

Many states are piloting and developing performance based rates (PBR). Based on observations, PBR should be accompanied by meaningful development of customer-benefiting advances in the areas of grid modernization, system optimization, energy efficiency, renewable resource development, and distributed generation deployment. Key considerations should include predictable mechanisms to ensure continuation of Missouri's historically low rates and reliable service, while also providing reasonable rate recovery for utilities to meet evolving customer needs by modernizing our electric infrastructure.

Specifically, discussion should focus on identifying meaningful and comprehensive performance metrics and milestones across a broad spectrum of quantitative measures to gauge achievement of the state's energy goals and to ensure utility accountability related to reliability, plant performance, environmental goals, renewable energy standards, customer satisfaction and engagement, energy efficiency, public and employee safety, and security. Metrics do need to be somewhat flexible or adaptable to change with newly acquired information.[2]

Efforts in Other States[3]

- Illinois's Energy Infrastructure Modernization Act implements formula rates, supports smart grid deployment, and funds programs to support electricity system innovation. It is estimated that over $2 billion in modern grid investments will be installed over the next four to six years, creating jobs, benefitting customers, and fixing aging infrastructure. Utilities which choose to participate must meet specific performance and investment mandates, with penalties for non-performance.

- Arkansas's Regulatory Reform Act of 2015 provides mechanisms for cost recovery of infrastructure investments. The act authorizes utilities to elect to implement a formula rate-review mechanism using a forward test year, and sets policies for determining a reasonable return on equity, recovery of the allowance for funds used during construction, and cost allocation and rate design. An annual review provides for revenue adjustments, with a cap of four percent.

- The Massachusetts Department of Public Utilities issued the "Modernization of the Electric Grid" order. The order requires electric distribution companies to submit a ten-year grid modernization plan outlining how the companies propose to make measurable progress towards the following grid modernization objectives: 1) reducing the effects of outages; 2) optimizing demand, which includes reducing system and customer costs; 3) integrating distributed resources; and 4) improving workforce and asset management. Utilities' modernization plans must include infrastructure and performance metrics to measure

[1] DE Comments, pages 14-15.
[2] Ibid, pages 12-13.
[3] Ibid, pages 4-5.

progress in achieving grid modernization objectives. Approved costs during the first five years of the plan are available for pre-authorization.[1]

- The Maryland Public Service Commission approved the utility installation of advanced metering infrastructure ("AMI") as a part of larger grid modernization efforts. As of 2013, there were approximately 1.6 million new electric and gas meters installed. Cost recovery of these efforts was contingent upon successful deployment and demonstrated cost effectiveness. Utilities were also required to develop customer education programs and cyber security plans associated with their AMI deployment, as well as monitor the costs and benefits of their investments.

- The California Public Utility Commission ("CPUC") adopted a policy that all electric customers should have advanced meters. Currently, advanced meters are in place for all customers whose demand is greater than 200 kW. California was the first state to pass a statewide grid modernization policy, which requires that unreasonable or unnecessary barriers to adoption of a modern grid must be identified and lowered. In September of 2009, the CPUC established an expedited review process for grid modernization funding, and since then the state has aggressively sought federal funding to support modernization efforts.

Broader Policy Reform Efforts

There are also two examples of broader policy initiatives that serve as national examples including efforts in Minnesota and New York. While there is a handful, these two were selected to address questions and statements shared by the Committee.

Minnesota's 21st Century Energy System Initiative (e21 Initiative)

e21 is taking a comprehensive approach towards addressing electric utility regulation through the promotion of renewable energy standards, energy efficiency practices, and performance based ratemaking standards. Unlike similar efforts in other states, e21 wasn't initiated by regulators or legislative mandate. In contrast to California or New York, both deregulated states, retail electricity prices are set by the Public Utilities Commission and are "relatively modest."[2]

The Initiative has brought together key stakeholder interests including consumer advocates, utilities, businesses, energy technologists, environmental advocates, academic institutions, and governmental agencies to accomplish initiative goals and lead in shaping Minnesota's 21st century energy system. The entities convening e21 included the Great Plains Institute, Center for Energy and Environment, Energy Systems Consulting Services, George Washington University Law School, Xcel Energy, and Minnesota Power and received funding support from the Energy Foundation, the Joyce Foundation and several utilities.

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[1] The National Governor's Association Center for Best Practices hosted a Learning Lab on New Utility Business Models & Electricity Market Structures of the Future in which several MA officials presented on a panel, ***Technology and Grid Modernization in Massachusetts: Changing the Relationship between Customer and Utility*. The slides are available by visiting,** http://www.nga.org/files/live/sites/NGA/files/pdf/2015/1507LearningLabMassachusettsretailelectricitymarket_Stevens.pdf **and** http://www.nga.org/files/live/sites/NGA/files/pdf/2015/1507LearningLab2015GridModernization_Davis.pdf**.**

[2] http://www.eenews.net/stories/1060028560

e21 aims to "develop a more customer-centric and sustainable framework for utility regulation in Minnesota that better aligns how utilities earn revenue with public policy goals, new customer expectations, and the changing technology landscape."[1] Minnesota stakeholders recognized the growing and fundamental misalignment of the traditional utility model, the regulatory framework that supports it, the realities of the marketplace today and the state's public policy goals. Proactively planning for an intelligent, flexible, efficient, and secure distribution system open to more participants over the next several decades that can handle new distributed energy technologies and the complexity of many more actors on the system will require a coherent strategy.[2]

It prompts investor-owned utilities (IOUs) and the Minnesota Public Utilities Commission (PUC) to consider modernizing both the electric grid and the regulations that guide utility operations. The e21 Initiative tasks both utilities and the Minnesota PUC to address current and future demands on the grid by: aligning an economically viable utility model with state and federal public policy goals; providing universal access to electricity services (including low-income customers); providing just and competitive rates; enabling delivery of services and options that customers value; promoting and fairly pricing grid services (including distributed energy resources); assuring system reliability, resiliency, and security while protecting customer privacy; encouraging investments that promote efficiency of the system as a whole; reducing regulatory administrative costs (e.g. fewer rate cases); and facilitating innovation and implementation of new technologies.

More specifically, e21 seeks to create a new performance-based, more forward-looking approach to ratemaking and incentives. "In place of today's frequent, costly—and by design adversarial—rate cases, e21 proposes that Minnesota provide an alternative option in which utilities that "opt in" are allowed to submit a forward-looking, performance-based business plan covering up to five years."[3] The longer planning horizon provides more predictable rates for customers and gives utilities sufficient time to achieve the desired outcomes committed to in the plan. The e21 consensus recommendations fit into four main categories:

- Performance-based Ratemaking;
- Customer Option and Rate Design Reforms;
- Planning Reforms; and
- Regulatory Process Reforms.

After e21 initiative approved the Phase I report "e21-inspired legislation"[4] (HF 1437[5], an omnibus economic development and energy appropriations bill) was filed in 2015 to allow utilities to file a multi-year rate plan with state regulators and request recovery based on meeting

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[1] e21 Working Group. December 2014. "e21 Initiative: Phase I Report – Charting a Path to a 21st Century Energy System in Minnesota," page 1. http://www.betterenergy.org/sites/www.betterenergy.org/files/e21_Initiative_Phase_I_Report_2014.pdf
[2] Ibid, page 1.
[3] Ibid, page 2.
[4] http://www.utilitydive.com/news/how-the-e21-initiative-is-building-smarter-utility-business-models-in-minne/400781/
[5] https://www.revisor.mn.gov/bills/bill.php?b=house&f=HF1437&ssn=0&y=2015

specified performance metrics. The legislation passed during the session but was vetoed[1] by the Governor due to a number of factors including unacceptable modifications to the net metering law. In a special session, a revised version of that bill (HR 3[2]) without the controversial language passed to enable multi-year rate plans (raised cap from 3 year to 5 years), encourage development of performance measures, and require distribution plans for any utility submitting a multi-year plan.

Minnesota stakeholders have begun work on Phase II objectives of e21 which includes forming subgroups to prepare white papers on performance-based regulation, grid modernization and integrated system planning.[3] The PUC launched a grid modernization process through a state proceeding to create more transparency in distribution planning, identify the best strategies for transitioning some utility revenue from the "cost-of-service model to a value- and performance based approach," and a separate but related process to examine rate reform options. [4]

New York's Reforming the Energy Vision (NY REV)

New York's effort, NY REV (now in its third year[5]), was initiated by the Governor with a goal of achieving a, "… consumer-oriented market that encourages innovative, market-based solutions that reduce costs while meeting critical environmental needs."[6] Similar to Minnesota's e21, it is designed to "reorient the electric industry and the ratemaking process toward a consumer-centered approach that harnesses new technologies and markets."[7] An emphasis is placed on shifting loads away from times of peak demand and on integrating distributed energy sources like solar, wind, and combined heat and power systems. The state's distribution utilities will be relied upon to offer such programs to gradually transition from a focus on the acquisition of generation resources to a focus on long-term transformation of the market that will result in more market-based approaches.[8]

The process focuses on clean energy, encouraging investment, and providing consumers with choice and affordability. To realize the expansive vision of NY REV, regulators separated the REV docket into two tracks. Track 1 focuses on the development and transformation of distributed resource markets and the utility as the distributed system platform (DSP) providers. According to PSC staff, under the customer-oriented regulatory reform envisioned here, a wide range of distributed energy resources will be coordinated to manage load, optimize system operations, and enable clean distributed power generation. Markets and tariffs will empower

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[1] http://www.mn.gov/governor/assets/2015_05_23_Veto_Letter_Chapter_80_tcm1055-114802.pdf
[2] https://www.revisor.mn.gov/bills/bill.php?b=house&f=HF3&ssn=1&y=2015
[3] http://www.rmi.org/elab_accelerator_2016_minnesota_e21_initiative
[4] http://www.utilitydive.com/news/how-the-e21-initiative-is-building-smarter-utility-business-models-in-minne/400781/
[5] State of New York – Executive Chamber. 2013. "Governor Cuomo Unveils 'Scorecard' to Measure Utilities' Performance."
[6] New York Public Service Commission Case No. 15-E-0302, *In the Matter of the Implementation of a Large-Scale Renewable Program*, Staff White Paper on Clean Energy Standard, January 25, 2016, Page 3.
[7]New York Department of Public Service. Undated. "DPS – Reforming the Energy Vision: About the Initiative." http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument
[8] http://aceee.org/blog/2015/03/new-york-s-rev-will-state-s-new

customers to optimize their energy usage and decrease electric bills, while stimulating innovation and new products that will further enhance customer opportunities. [1]

Track 2 focuses on reforming utility ratemaking practices and regulatory system and revenue streams to accommodate the new utility as DSP provider model. The commission process has allowed for business model reforms including the opportunity for market based earnings (MBEs), incremental ratemaking reforms to the utility revenue model, and rate design reforms to reflect the needs of the evolving marketplace. The New York Public Service Commission adopted several orders to date to implement a scorecard model,[2] which involves the development of metrics both for the purposes of performance-based ratemaking and tracking the extent to which the NY REV initiative's policy goals are met.[3] One scorecard developed by the New York Public Service Commission involves the measurement of reliability.[4] An "earnings adjustment mechanism" was also adopted to incent peak reduction and system efficiency, energy efficiency, small system interconnection, customer engagement and information access, greenhouse gas reductions, and affordability.[5]

7. Diana Vuylsteke, Managing Partner, Bryan Cave, Representing Missouri Industrial Energy Consumers (MIEC)*

Ms. Vuylsteke testified that both utilities and consumers have a common interest in maintaining a good business environment in Missouri. Ms. Vuylsteke testified that she represents large power consumers, who employ over 120,000 Missourians, to ensure that rates are fare and service is reliable. Ms. Vuylsteke made several recommendations relating to the future regulation of utilities in Missouri, including strengthening Public Service Commission utility oversight by being able to increase utility rates while preserving a strong review process. She testified that utilities should not be micromanaged, but that both consumers and the Public Service Commission should have plenty of information in order to make informed decisions during rate cases. Further, Ms. Vuylsteke testified that MIEC supports grid modernization, but that investments should not be further incentivized. She testified that further incentives for infrastructure investments have resulted in unnecessary rate increases in other states. She

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[1] http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf, pages 2-3.

[2] See, for instance: 1) New York Public Service Commission Case No. 13-E-0140, *Proceeding on Motion of the Commission to Consider Utility Emergency Performance Metrics*, Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages, December 23, 2013. 2) New York Public Service Commission Case No. 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, May 19, 2016.

[3] New York Public Service Commission Case No. 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015, page 130. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d

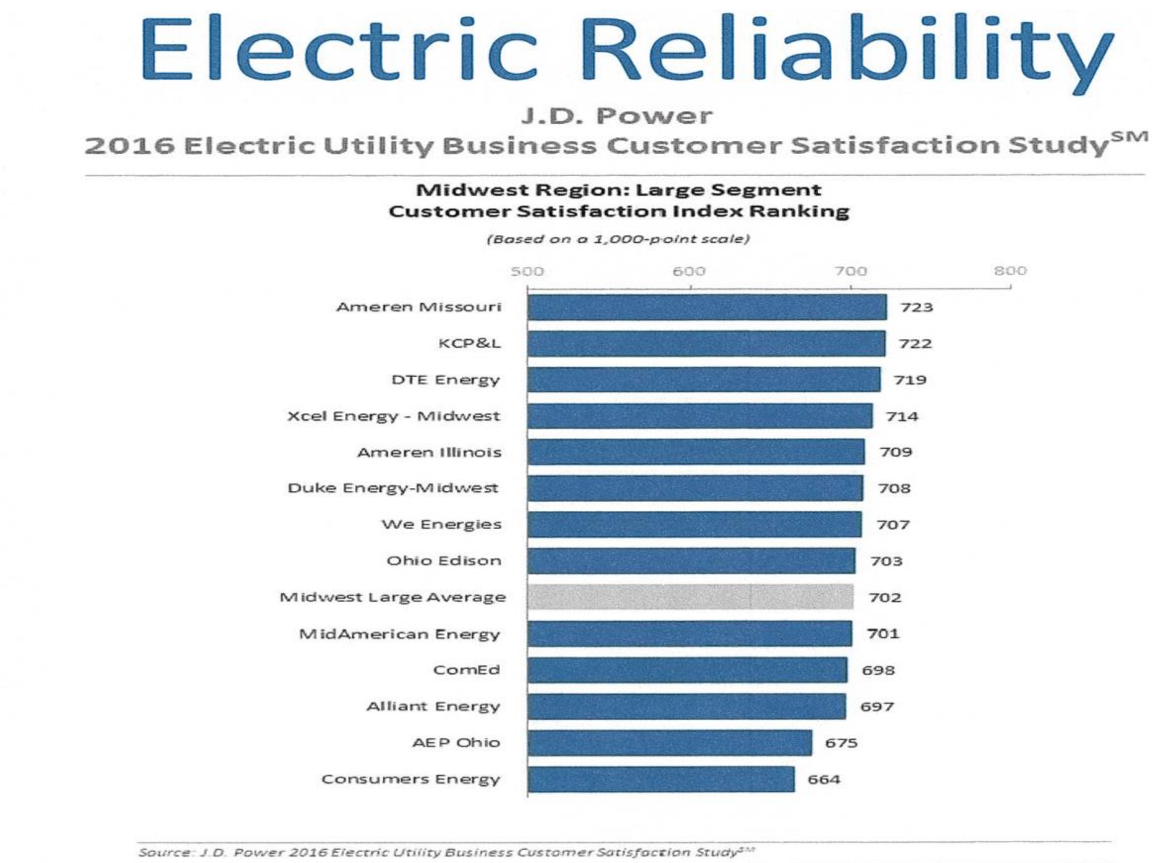
[4] New York Public Service Commission Case No. 13-E-0140, *Proceeding on Motion of the Commission to Consider Utility Emergency Performance Metrics*, Order Approving the Scorecard for Use by the Commission as a Guidance Document to Assess Electric Utility Response to Significant Outages.

[5] New York Public Service Commission Case No. 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, pages 71-93.

suggests that if the Committee could assist in detailing the infrastructure that is needing to be replaced or constructed, MIEC could assist in ensuring that appropriate rate increases occurred in order to finance such replacement or construction costs.

8. David Woodsmall, Midwest Energy Consumers Group

Midwest Energy Consumers Group represents over 50 commercial and industrial consumers. In assessing utility regulation and infrastructure investment, we should compare Missouri electric reliability, investment levels, and the financial status of utilities to that of other similarly situated states. First, we should assess if Missouri utilities are providing reliable electric service. According to the figure below, both Ameren Missouri and KCP&L are the most reliable according to the J.D. Power 2016 Electric Utility Business Customer Satisfaction Study.



Second, we should assess whether Missouri utilities are incentivized to invest. Together, Missouri utilities are investing regularly, as evidenced by the chart below. Further, utilities are investing in both necessary and discretionary infrastructure, including investments in items such as electric vehicle charging stations.

Electric Investment (Since 2006)

Utility	Investment
Ameren	$4.9 billion
KCPL	$3.8 billion
GMO	$1.6 billion
Empire	$1.2 billion

Third and finally, we should assess the financial status of Missouri utilities. Amongst other utilities, the chart below demonstrates that Missouri utilities fit well within other Midwestern utility credit ratings.

Utility Financial Condition

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

Further, the stock prices of Missouri utilities have steadily increased as demonstrated below.

Utility Financial Condition

In sum, Missouri is not in need of changes to utility regulation and infrastructure investment due to the fact that Missouri has reliable electric service, Missouri utilities consistently invest in both necessary and discretionary infrastructure, and due to the fact that Missouri utilities are financially healthy as evidenced by both credit ratings and stock prices.

9. Caleb Arthur, CEO MO Sun Solar & Smart Energy Solutions, President, Missouri Solar Energy Industries Association (MOSEIA)

I am Caleb Arther, CEO of Missouri Sun Solar & Smart Energy Solutions. I also serve as the President of MOSEIA, and am the Vice President of the Missouri Clean Energy District (Missouri Commercial and Residential PACE).

We have over 1,200 solar customers, 200 energy efficiency customers, and 50 battery storage residential and commercial customers spread throughout the state of Missouri. Our goal is to provide cost effective free market solutions to our customers through private investments that have totaled $30 million of revenues in our first four years of business with a guaranteed customer electric savings of $80-$90 million. Recently, Sun Solar was ranked by *Inc. 5000* magazine as the nation's 9th fastest growing private energy company. We also have the privilege of being ranked as the 2nd fastest growing company in Missouri. Sun Solar has 130 employees and is growing. Over 98% of our solar customers are net metered and tied into the local utility grid.

Distributed generation (customer side) solar and battery storage will and do play a huge part in the grid modernization portfolio of every state, including Missouri.

From the Electric Power Research Institute

Our current electric grid uses many technologies that date back to the time of Thomas Edison, requiring the electricity industry to seek new ways in which power can be generated, delivered, and used in ways that minimize environmental impacts, enhance markets, improve reliability and service, reduce costs, and improve efficiency. Utilities are beginning to modernize the electric grid through the gradual development of a “smart grid” that uses information and communication technologies to manage electricity more efficiently. Due to the complexity, number and scale of the systems and devices involved in a smarter grid, technology communication between the various systems is key to successful implementation. Research can address these issues while furthering innovation in grid modernization efforts.

Missouri has a great foundation for solar being tied to the utility grid. A recent study paid for by local utility shareholders showed that solar net metering provides a net positive benefit for all ratepayers and the utility. When you have solar panels pumping clean renewable energy into the grid you get frequency regulation, voltage regulation, and security for the grid. You offset carbon emissions and also build a generation portfolio that didn’t cost anything for other ratepayers to build. Most solar systems will produce twice the amount of power a typical home consumes during the day. This energy is resold to their neighborhood through the utility companies’ electric lines.

Sonnen lithium batteries work not only for power outage but load shifting and peak power shaving. The system reads a 3-day weather forecast and creates a model for peak efficiency. All utilities need to do is help finance through the existing electric bills and educate ratepayers on why they need a lithium battery storage solution tied into their grid. Then the utilities would get access and partial control of the battery storage to help out its grid at a local level.

The Missouri Governor’s Conference on Economic Development two years ago stressed that our electric grid as the #1 target for terrorist attacks because it has almost all centralized power in just a few areas, mostly outdated coal plants within 10 years of retirement.

We need as a state to take a holistic approach that’s cost effective and a solid long-term investment for everyone involved.

Here’s a summary of what states are doing to modernize their grid and allow for third-party ownership of solar systems, at the state legislative level:

> <u>Washington</u>: The state is giving out $12.6 million in Clean Energy Fund grants to five utilities in Washington. The money will be used to build a battery and solar training facility, construct a battery, electric car and solar microgrid, deploy a community solar system, create a solar-powered microgrid at an emergency shelter (so it can run when the grid is down), and pilot a “shared energy economy” model.
>
> <u>Massachusetts</u>: The state legislature last week passed a bill that could make the state the third in the nation to have an energy storage mandate. By 2021, commercial storage economics will be favorable for certain utility traiffs with demand charges as low as $11/kWh per month. Many utilities in Missouri already have demand charges over this amount.
>
> <u>Rhode Island</u>: In June 2016, the legislature enacted HB 8354, which increased the system

size limit for net metering, established community net metering, and enabled third-party ownership options for all customer types in the state.

Georgia: The Solar Power Free-Market Financing Act of 2015 allows power purchase agreements (PPAs) for the construction and operation of solar systems. Previously, residents had to own the solar on their rooftop and could only sell it to their utility.

North Carolina: Is currently considering HB 245, the Energy Freedom Act, which would for the first time allow property owners in North Carolina to buy electricity directly from a renewable energy company, bypassing their utility. The bill would provide greater energy security and reliability through the development of distributed energy resources, and it would encouarge private investment in new generating facilities and ancillary businesses.

Also, I have provided a great article on third-party ownership in the Southeast from the Rocky Mountain Institute. The key passage:

Across the county, third-party ownership is becoming as prevalent in the rooftop solar market as leasing is in the car industry. In fact, in 2014, when one-quarter of all car sales were leased – the highest rate of car leasin than at any time in over a decade – two-thirds of all new residential solar installations were third-party owned.

Similar to car leasing, third-party solar ownership can be advantageous for a number of reasons. Many residents do not have the full upfront investment capital for solar systems and lack knowledge of local permitting and incentive programs. Other entities, like non-profits and schools, cannot access tax credits and rebates that companies can access. And for many others, installation and maintenance are major barriers. Therefore, it often makes sense to involve a third-party developer in investing and installing a solar system. Residents sign long-term contracts in excahnge for electricity prices typically lower than retail rates.

Third-party ownership of solar typically takes one of two forms: a lease or a power purchase agreement (PPA). Under a lease, the lessee pays a fixed monthly fee that is not tied to the amount of power generated, while under a PPA, the lessee agrees to purchase all of the electricity produced by the solar system. Increasingly, companies like SolarCity, Sungevity, and Sunrun have seen success in the residential solar market. In fact, third-party owned systems make up 60%-90% of new residential systems in Arizona, California, Colorado, and Massachusetts. And in Georgia, third-party ownership could accelerate an already booming solar industry.

Thank you.

Individual Testimony
October 25, 2016

1. Richard Sedano, Principal, Regulatory Assistance Project

Introduction
My name is Richard Sedano. I am a principal with the Regulatory Assistance Project, and I run its U.S. Program. RAP is a global non-profit organization with offices in the United States, China, Europe, and India. RAP provides policy and strategic advice to government decision-makers. RAP is funded by foundations and governments. I joined RAP in 2001. From 1984 until 2001, I served with the Vermont Department of Public Service, and from 1991 until 2001 I was commissioner. I began my career with Philadelphia Electric Company as an engineer in power generation. I received an undergraduate engineering degree from Brown University and a graduate degree in engineering management from Drexel University.

My testimony is about how regulation in the United States is changing to reflect inexorable advances in technology and resulting changes in customer attitudes. These are supported in some states by nurturing policy. Federal policy has also been supportive, but I will not be discussing federal policy in my prepared remarks.

I will try to define my terms and avoid assuming anything about what a reader knows. Electricity systems and regulation are pretty arcane.

I define the power sector as the twinned utility company and regulator. They are intertwined. Also, the term resources, as in Integrated Resource Planning, tends to mean sources of products, like energy or kWhs, capacity or kW, of ancillary services of several kinds, like reserves and voltage support, and also means resources that can avoid these (some people call these negaWatts). A utility can manage and plan for resources. The gas and water industry products are simpler.

The power sector is changing because technology is enabling fast processing and communicating of information and because the ability for customers to produce resources the grid needs has grown exponentially over the last two decades to the point where it is making a meaningful difference in resource acquisition and utility capital planning. By ability, I mean improvements in cost and convenience. In addition, natural gas-fired generation is inexpensive compared with coal-fired generation, and nearly zero marginal cost variable grid scale sources, wind and solar, are increasingly competitive, changing how the grid operates. Some states now say that the expect 80%-100% of incremental resources to come from customer resources, that retiring central station resources can be replaced with smaller scale resources and that significant wires investments at both T&D levels can be delayed or avoided. Finally, decarbonization of the power sector is likely to be an increasing driver of future investment and regulatory choices with diminishing cost impacts.

This session focuses on how utilities are compensated, how they are motivated, and how regulators manage this system.

Business as Usual Utility Regulation

Today, investor-owned utilities are able to post net earnings based on an allowance in the revenue requirement[1] to compensate equity investors for the capital they turn over to the utility in exchange for stock[2]. This allowance is calculated in several established ways, and each way may come out a bit differently. The regulator has to choose one answer, and it is always within the range created by the lowest and highest answer. Often it is in the middle. There is little science to this final step.

A utility bottom line can also be affected by whether revenues are higher or lower than anticipated when the revenue requirement was calculated, or if costs are higher or lower. Compared with the assumptions, reality always produces different results. First I will talk about revenues.

If revenues are higher than expected[3], the utility has no obligation to give this money back. It can do the following:

1) Keep the money – if costs come in as anticipated, earnings will be higher than anticipated (overearning), the only issue is whether there is a public backlash about a monopoly overearning. If the overearning is still within the range of calculated returns, this outcome can be effectively justified;
2) Ask the regulator for an accounting order that applies the overearning amount to write down capital accounts in the rate base – this reduces the amount of money that will be collected from customers in the future, a consumer benefit, and allows posted earnings to hit the target; or
3) Use the excess to offset unexpected cost increases – a cushion.

If revenues are lower for the reasons above and also potentially due to customers demanding less electricity from the utility, there is no obligation to make up lost revenue.

Over the last thirty years, government has asked utilities to be the instrument of public policy to help customers use less electricity. Utility energy efficiency programs have saved money for society and for individuals by substituting more efficient end uses that are cost effective, and which deliver a combination of education, technical assistance and financial incentives to motivate customers to change. The accumulated effects of these energy efficiency programs and resulting customer actions reduces sales from what they otherwise would have been and avoid more expensive utility costs.

Utilities have observed that some of the revenue to cover embedded costs from the last revenue requirement disappear when associated sales disappear. There are the following solutions:

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[1] The revenue requirement gets decided in a rate case, it is the amount of money a utility needs to collect in a year in order to deliver safe and reliable service, meeting all state policy directives.

[2] Some of this money is returned to investors in dividends, other money is reinvested in the company, some goes to pay for expenses not typically allowed in customer rates like lobbying expenses or some employee bonuses.

[3] This can happen because of extreme weather, a growing economy, robust sales of excess power to neighboring utilities or other random events.

1) Do nothing – the utility manages the risk of uneven earnings;
2) Recalculating the revenue requirement – an annual rate case is effective, but is expensive – if underlying costs don't change much, this is a lot of work to reconfirm what the last revenue requirement concluded;
3) Creating a lost revenue adjustment – this is not very effective because while it accounts for savings counted in utility efficiency programs, it does not count other changes plus and minus and leads to significant error;
4) Decoupling – an effective solution that relies on the revenue requirement found in the last rate case – utility revenue above or below target is reconciled with an upward or downward adjustment[1]; or
5) Raising the monthly customer charge to cover all embedded fixed costs – this is effective, but has negative side effects[2]:
    a. Having service becomes much more expensive, especially for low volume users;
    b. It removes significant opportunity for the customer to manage the total utility bill;
    c. It distorts and minimizes the value of customer resources compared with utility resources[3]; and
    d. It violates a long standing practice of rate design of using the customer charge for anything more than the cost of connection.

I promised to talk about what would happen if costs are higher or lower than anticipated in the last revenue requirement calculation. Let's assume revenues came out on target. If costs are lower, the utility over-earns. See the prior discussion about over-earning. Hopefully, this outcome was produced by savvy utility management, and the benefits will be captured in a future rate case. It could also have been driven by forces outside the utility control (weather, the economy). Hopefully, it was not produced by cost cutting that sooner or later will compromise reliability or customer service, though there are instances in utility management in the U.S. when this occurred and performance problems did ensue.

If costs are higher (driven by forces already discussed, or perhaps unexpected health care or labor costs), the utility under-earns. Structural cost increases will lead the utility to petition to reset the revenue requirement higher.

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[1] The customer can see this on the bill as a rider, or it can be buried in the rate. The effect of each is the same. Since customers tend to view the rider as extraneous information, burying it in the rate is my preference. Some do not trust decoupling because it changes the rate without a full investigation of the revenue requirement.

[2] Full implementation of this idea would put the customer charge for an electric utility at around $60-70 per month. Some utilities have made modest increases in the customer charge, to $20 to $30 per month. This approach causes less of the impact from the side effects listed here, but also renders the idea ineffective in actually addressing the core concern, which is utility revenue stability.

[3] This session is not about rate design. However, since rate design and utility compensation are related by this option, I will note the following. If customers are to be a key grid resource, then the investment signals seen by the utility and customer should be consistent to achieve optimal investment balance. Thus, the price signal the customer sees, the incremental cost of using or saving the next unit of energy, should be consistent with the value embedded in utility resource decisions around acquiring power or building capital assets. If this balance is off, customers will be motivated to over or under invest – if the customer charge goes up high, the energy charge is reduced, undervaluing customer resources – more expensive utility resources ensue, and the overall cost of utility service in Missouri is higher than it needs to be, essentially a drain on the Missouri economy that would rather use excess money for better purposes. Further, a very high customer could motivate some customers to fully self-supply, exiting or defecting from the grid. New customer options create a constraint on rate design that did not exist before.

The remedies discussed operate in distinct ways on each of these situations. Decoupling is the only one that addresses all these events while minimizing the need for revenue requirement cases and leaving rate design unaffected.[1]

One of the most annoying things I recall from my experiences in government was the utility executive speech, often to shareholders, hoping for a hot summer or a cold winter in order to achieve higher earnings. This underscored an attitude incompatible for a company affected with the public interest that extreme weather, which may cause problems for its customers and communities was good news for the utility. Utilities are not like other businesses, for whom volume is always good.

When volume of sales affects utility earnings in this way, the throughput incentive is present. The utility is motivated to increase sales, whether or not that is good for the state, and to discourage reductions in sales. In the 1960s, each added sale was provided by low cost sources, growth was equated with prosperity and pollution and other externalities were unrecognized. Today, each added sale has quite different marginal cost and environmental implications.

States that have achieved the highest results from energy efficiency programs have managed to eliminate the throughput incentive. Decoupling is widely used among these states.

The Future Utility Looks Different from the Past, What Should Regulation Look Like?

Recently, the trends I cited earlier, technology and more and varied customer resources, have caused significant rethinking about the ways utilities are compensated, and even about the role the utility plays in civil society.

Regarding the utility role, if populations of customers are now a meaningful resource, a resource we want to learn to count on, the utility is not so much “producing” a result, which customers “receive,” but “enabling” a result, in which customers are “participating.” This is quite a change! Some think this idea is hyped or overblown, and some express the “if the grid is not broken, don’t fix it by letting society get too dependent on these new technologies.” My own view as a trained engineer is that you don’t stop technology. So words like “adaptive” and “integrating” become more important to characterize what is going on. Some say that these changes will not come to low cost states, a state like Missouri. My own view is that it is just a matter of time before the attractiveness of new resources and technologies becomes ubiquitous. While experts may not know all the ways these changes will manifest, I think they are real, irreversible, and can be beneficial if the power sector evolves to accommodate them.

Among the states, the field is stretched out. At one end are states like Hawaii, with huge penetration of solar PV and strong participation in energy efficiency. There, change is happening faster than the state can respond. Other states, such as Arizona, California and Rhode Island, are starting to see significant effects on system planning and operations. New York is taking a comprehensive reassessment of the power sector in a magnum docket known as New York Reforming the Energy Vision, or NY REV. California has similar ambitions, though the

[1] This session is not about rate design. However, part of power sector reform discussions in those states where the subject is active is about whether flat rates should be replaced by rates that convey information about the time-differentiated value of electricity, time-varying rates. Decoupling is compatible with this change.

approach there is a series of dockets representing puzzle pieces that are coming toward a whole vision. Smaller states, among them Rhode Island and Minnesota, are taking on bite size challenges with the long term trends in sight. At the other end are states where solar PV deployment remains less than 0.1% of customers, not yet registering as a force of change.[1]

Aside from maintaining bedrock utility functions in reliability, safety and service, should there be changes in the role of the utility in light of the changes we have discussed so far?

Briefly, many say yes, though there is divergence about the nature of the change. Here are two points toward the ends of a continuum:

1) In one view, the utility retains its delivery role, but operates as an enabler for customers to make contact with companies that will help them generate power, store power for use later, or manage their end uses to produce value for the grid (demand response). This represents a strict interpretation of the utility monopoly as the delivery company. For a vertically integrated state, this would seem to be a radical shift, though the utility would retain the job of being a backstop provider of resources for customers.
2) In the other view, the utility maintains control of the customer relationship and becomes the catalog for validated services the customer can use. The term used for this is "intermediation." The utility intermediates between the customer and the many service providers that might provide value. This represents using the economy of scope of the utility to accelerate deployment of new services. Note that service providers failing to impress the utility will have to find another way to reach customers. For a vertically integrated state, this would seem to be an evolutionary shift.

Within the continuum represented by these, the government can allow a utility into some businesses and keep them out of others.

In all cases, the utility becomes interested in helping to deliver services that customers want. This provides an opportunity for the utility to reap revenue and net income from these activities, a new opportunity. This may feel unfamiliar to utility regulators, though regulators of the 1990s had to deal with similar disruptive forces with telecommunications companies. To assure focus and alignment on value-driven services, it is beneficial if the throughput incentive has been removed.

Compensating the Utility

Another way the power sector of the future has developed is to consider whether compensating utility investors through a return on capital investment alone, the current approach[2] is consistent with public policy. What does public policy suggest? Some capital assets are large, expensive and risky (from permitting risk, siting risk, construction risk, risk of having been the wrong investment and more). While the utility experiences these cost risks at first, in most cases, customers eventually pay for everything. Some capital assets can be avoided with customer resources. Customer resources tend to be small, avoiding some risks endemic to large utility projects. Also, a significant share of the cost of customer resources is paid for by someone other

[1] Though some utilities in this situation have taken steps to change rate design to protect against sales declines that have not yet occurred.
[2] If the throughput incentive has eliminated the opportunity to profit from higher sales.

than the utility, so these costs do not go into rates. Summarizing trends, the costs of customer resources seem to be dropping (while capabilities are rising) while many utility resources costs are rising.

Many experts and utility executives agree that there is a bias in utility problem-solving to use capital assets preferentially. It's understandable given the rules. The utility earns on capital assets and does not earn on routine expenses. Even when a portfolio of expenses to help customers use their newly available resources to solve a grid system problem is optimal, the utility may not study it or consider it and the capital solution will tend to be advanced.[1] This capital bias raises costs higher than they otherwise need to be while causing missed opportunities to invest in customers' buildings, systems and processes.

If we want to consider another way of compensating, what would that be? The answer many are working on is to create a return on performance. How would that work?

First, we decide what important societal objectives the utility can influence. A sample list: reliability, universal service, resilience,[2] environmental/health quality, safety, economic development.

Utilities do many things that further these societal objectives. What are they? And how might they be changing in reaction to these technology and customer trends? Whatever they are, to the extent that utility performance can be measured cleanly, we encounter another question: is there an increment of performance beyond what would be considered compliant that has incremental value to the state?

For some metrics, better performance is better for society, for others no. Next question: for those metrics where more is better, why should the utility try to achieve more?

Under traditional regulation, achieving more performance adds cost, with no revenue. This leads to under-earning.

With the throughput incentive resolved, there is still no reason for the utility to produce more than adequate results.[3]

Some argue that if better performance is possible, the utility should deliver it. Readers can judge whether this is credible. In my experience, utilities are experts in identifying and delivering compliance.

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[1] A now well-known example of this is the Brooklyn-Queens Demand Management project in the Con Edison service area. Briefly, the utility brought a conventional sub-station upgrade to New York regulators. The regulators, however, challenged the utility to solve the problem with customer resources. The upgrade has been shelved and the utility is gathering customer resources to solve the problem. The regulator agreed to a favorable regulatory treatment for the associated expenses that will allow the company to earn a return on them over ten years.

[2] Resilience is an emerging term referring to the ability of a network to continue operating despite assault from natural or human attack AND the ability of the network to recover quickly after such an attack causes a loss of service.

[3] Some utilities target performance in the second quartile, on logic that resonates in Lake Wobegon, that above average, though perhaps not exceptional or innovative is the objective.

The terms performance regulation or output regulation are used to describe a system of utility regulation in which enough of the utility net income is riding on performance that it changes the way the company is managed to find the best solutions. Enough can be money. Enough can be a public report card that tells everyone how they did. A combination of both, where many metrics are measured and reported, and a subset produces a return, is likely to be best.

In this way, the utility return reflects its success in delivering societal objectives (not just how much money it invested), and the vital importance utilities contribute to civil society can be seen more clearly. Drucker said "you manage what you measure," readers can judge how often this is true.

What should happen to the return on capital? Some suggest that it should be removed, but I think this path is not realistic. It remains important for regulation to offer a return on capital since the lifeline to financial markets requires it. But it can be lower, perhaps at rate equivalent to utility debt. Regulators can offer a return on selected expenses that avoid costlier capital assets. Performance and perhaps service profits can make up the difference. In my work with states, I suggest they consider that they permit earning at least up to the top of the range of returns to motivate utilities to excellence through innovation or whatever added effort is needed to achieve superior results.

Performance regulation has challenges. Regulators must sift through metrics already used by utilities and consider the need for new ones to decide what to measure. Rewards should be associated with exemplary, beyond normal performance – is there a continuous scale for reward or a threshold well beyond business as usual that yields a significant reward? How shall the regulator assure that the utility will not overlook performance in areas of the company not subject to a performance reward or report card? Will the commission and the utility be able to convince financial market analysts that performance based regulation is superior to business as usual?

Other changes to state regulation are likely to emerge individually or in packages. Among these include:

- Enhanced distribution planning in order to reveal sources of value that customer resources can address and introduce new methods to reflect a two-way system;
- Rate design changes that motivate customers in value-based investments and operating choices;
- Improved processes for customers to access the grid and valuable services;
- Improved access to data including customer data for them to use, and aggregated data for service providers to use for marketing with utilities getting more involved in data analytic methods to create insight and intelligence out of the data reservoir they control.[1]

Note that all of these have in common the idea that there is unrealized value in the system today, and that more opportunities for value will emerge.

[1] Cybersecurity is a concern today, as routine headlines indicate. Utility regulators are already becoming part of the nation's mesh defense against attacks. There remain reasons to get the most benefit out of data collected by utilities.

Designing Innovation into Utility Regulation

My final point will be evident to anyone who has been in a fast changing environment. Failure is not only possible, it is likely. Some ideas will not work as we hoped they would. How does utility regulation react to failure? Generally, utility regulation punishes any failure it finds. Inaction is generally not found out and not punished. Inaction is safe in traditional regulation, where the safest plan is to do next year what we did last year. There tends in utility regulation to be no structural learning from failure.[1]

With the changes I have talked about here, innovation will be necessary to bridge the gap between today and tomorrow. Does regulation have to change to accommodate innovation?

Regulation can add structure to innovation by paying attention to demonstrating how new trends in technology and customer options can manifest for real in real communities with real people doing real things and making real investments with the real help of the utility. This is regulation being "adaptive" to "integrate" new ideas. Demonstrations are expensive. They can engage communities and produce value. They generate learning and experience through success and failure that can be deployed at full scale. In a utility of significant size, meaningful demonstrations can represent a small percentage of the revenue requirement, and may be seen as analogous to the high risk part of an investment portfolio, an investment in the learning that can only come from pushing beyond what we know for sure.

Progress and Outlook

What are other states doing? No state is moving with more purpose in the direction of embracing the future than New York. Regulatory reform there is in the midst of adopting performance regulation. The commission there issued a series of policy and implementing orders, and is now implementing it all in the first subsequent utility revenue requirement case. Demonstrations of integrated innovations in technology, customer engagement and utility compensation are underway in the territories of all investor owned utilities, nurtured by regulation.

No state is moving with more urgency than Hawaii. With rates as high as they are there and policy to end the state's dependence on fuel oil, customers have been quick to deploy options as they have become available. The pace of change on the islands has outpaced the utility's response (without going into what they should have done, there were no performance standards) and the commission has said that performance standards are necessary to help guide the evolution of the utility. The commission is managing very fast change in catch up mode.

No state has had more legislative push toward reform than California. Regulatory reforms underway are implementing a series of laws to affirmatively rely on customer resources first. The commission there is mightily trying to create a coordinated procession of policy reform dockets to implement state policy. Performance regulation has not yet emerged on the regulatory

[1] I want to credit the good utility employees who do take initiative out of dedication to their profession. I was once in these ranks. Regulation does not acknowledge this and many utilities are seen as places where innovation is the exception, not the rule. I also want to note the that over-spending for power generation in the 1980s and resulting bankruptcies are an example of failures leading to structural changes, but these were catastrophes, not intentional experiments.

agenda there, though they have a robust community choice aggregation initiative – towns reflect their judgment of utility performance if they decide to source their resources themselves. Several other states are studying the role of the utility and utility compensation to better "align" (another word often used in this context) utility performance with societal priorities (performance regulation) and customer interests (services). Washington DC and the states of Maryland, Rhode Island, Massachusetts and Minnesota have processes underway sponsored either by the commission or by stakeholders to look at these questions, and I am aware through my work with states that others are actively working on it in advance of public activity. Vermont's dominant investor-owned utility is using latitude in regulation to experiment with technology and offer a range of new services to customers.

Americans are also paying attention to a performance regulation system put in place by the United Kingdom utility regulator to apply to all distribution and transmission companies. The system is known as RIIO, revenue = innovation + incentives + outputs and is in its first cycle.

In nearly every case, progress is moving in a collaborative setting. Innovation seems more conducive to this approach compared with the evidentiary process that commissions typically use.

Conclusion

This is a time of change driven by technology and customer attitudes. Decarbonization is likely to add fuel to the change engine. These changes are likely to roll through the US over the next decade. States are wise to be intentional about utility regulation in this cusp of time, making sure to the extent possible it promotes alignment with the objectives of policy and reaping new benefits. Beginning a process in Missouri for assuring this alignment is how I interpret the charge of this committee and how I have approached assembling these dense remarks. I appreciate the opportunity to deliver them to the committee.

2. Natelle Dietrich, Staff Director, Missouri Public Service Commission

Members of the Committee, I am Natelle Dietrich, Public Service Commission Staff Director, and I am happy to speak to you again today to summarize Staff's Report in the working case the Commission opened in June to consider policies to improve electric utility regulation in Missouri. In its docket, the Commission invited interested stakeholders to submit suggestions for policy changes.

On October 17, the Commission Staff submitted a report to the Commission describing and evaluating the submitted suggestions, and offering its recommendations for any actions to be taken by the Commission. The members of the Committee should have received a copy of the report around October 17.

In comments, 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". Consumer groups claim that overarching metrics indicate the current regulatory framework is working, and regulators and legislators should be hesitant in making sweeping changes. In Staff's opinion, 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.

Through the working docket process, Staff asked the questions:

1. Is there a problem that needs to be addressed?
2. What investments are you (the utility) not able to make under the current regulatory environment that you would be able to make if there was a change in ratemaking practices? and,
3. 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 such as performance-based rates, shortened rate case timing, an electric ISRS.

In preparing the report, Staff reviewed all comments submitted to the docket, held a workshop to seek additional input and clarification, reviewed a number of publications, and met with utility representatives, including a meeting with Ameren Illinois. While Staff is not convinced there is a problem with the current regulatory environment to the extent raised by the utilities, the comments suggest some degree of policy or legislative reform could be beneficial to the Missouri regulatory process. As I will explain, in the report Staff does not recommend sweeping legislative changes, but recommends or does not oppose reforms that are largely within the Commission's current statutory authority.

So - Is there a problem?

The extent of the "problem" depends on how one views the information presented. For instance, one cannot just consider investment costs or consumer benefits, but must also include off-sets for things such as reduction in costs due to automated processes or efficiencies gained from new technologies. As an example, during the meeting with Ameren Illinois it was presented that advanced metering infrastructure or 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.

Staff met with Ameren Missouri and Ameren Illinois to get a better understanding of Ameren Missouri's investment needs, but also to understand the improvements that are often touted as a result of Illinois legislation. But – one cannot easily compare Illinois and Missouri. What became clear from the tour – Illinois has a different infrastructure system design, and has had issues with reliability that Missouri does not have. Missouri is already there. For instance, Missouri already has automated meters - AMR and some 2-way advanced metering infrastructure - AMI.

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

Therefore, regulatory changes should incentivize grid modernization and replacement of aging infrastructure – not incentivize what is already being completed under the current regulatory environment.

Switching to regulatory lag - In Staff's opinion, regulatory lag is not inherently bad. There is a difference between the utility "losing money" and not earning its authorized return. Utility comments suggest the electric utilities have been able to invest what is necessary for the provision of safe and reliable service, but may not be able to invest in aging infrastructure or infrastructure to meet Missouri's future energy needs without "a realistic opportunity" to earn their authorized return.

Western District Court of Appeals (9/6/16) – Regulatory Lag
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 September 2016 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."

"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."

Other States
Much like the previous Senate Interim Committee hearings, Staff also reviewed the regulatory environment in other states. Some observations include:

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

Second, where the 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 construction work in process (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.

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.

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). 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.

Staff's Recommendations

Based on Staff's review of all the information submitted in the docket, in its report, Staff recommends:

1. Any reform give Commission discretion ("tools in tool box") – In other words, allow the parties to recommend a ratemaking proposal and the Commission to develop approaches based on such things as:
    - Different utilities have different needs – one size does not fit all
    - New technologies
    - Environmental mandates
    - Changing circumstances
    - Facilitate replacing of aging infrastructure and incentivize grid modernization
2. Any reform designed to encourage grid automation or infrastructure replacement should include a requirement to submit, for Commission approval, a 5-year investment plan, which includes annual progress updates.
3. The Commission should retain the ability to review and audit the books and records of utilities operating under its jurisdiction.
4. If the risk faced by Missouri utilities is materially changed, the change in risk should be taken into account when setting the utilities' authorized return.
5. Any changes preserve current incentives for utilities to operate efficiently.
6. Any changes preserve matching in a utility's revenue, expense and rate base values.

Specific proposals for reform

In the report, Staff notes it is not opposed to the following specific proposals for reform:

a. 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.
b. Trackers/Riders considered on a case-by-case basis based on all relevant evidence.
c. Interim rate increases.

d. An electric ISRS that is implemented similar to what is expressly allowed for water and natural gas utilities.
e. An electric rate case adjustment proceeding that includes the traditional 11-month rate case every 3 years, with an annual 7-month rate case adjustment to update the revenue requirement and rate base, and includes certain other consumer protections.
f. A decisional pre-approval process with post-construction review of costs and timeline to complete the project.
g. A grid modernization mechanism to allow timely, efficient and prudent cost recovery to utilities for automating and modernizing the grid that also includes performance metrics and milestones, an investment floor and ceiling.

There were also several more targeted proposals for reforming the Missouri Energy Efficiency Act, the renewable energy standards, low income rates, and workforce development, to name a few. In the interest of time, those proposals will not be summarized today, but we would be happy to answer questions on any of them, what I have summarized or other aspects of the report. According to the Commission's order opening the working docket, the Commission is expected to issue a final report based on Staff's analysis by December 1.

Chairman Questions and Committee Member Responses

As Committee Chairman, Senator Emery posed the following questions to Committee members for discussion during the October 25, 2016, executive session of the Senate Interim Committee meeting:

1. What is your personal assessment of the adequacy of the status quo?
2. What is your sense of the direction the committee and legislature should pursue that will best facilitate Missouri's economic health and growth?
3. Do you have any comments in support of, or opposition to, any particular regulatory model that was discussed in public hearing or to which you have been exposed otherwise?
4. What is your reasoning in support of your views?
5. Do you have any specific questions that must be addressed in any compromise?
6. May I distribute your written comments to other committee members if received prior to the hearing date?

Senator Romine's Response

1. What is your personal assessment of the adequacy of the status quo?

   The current system appears to be working well as a significant amount of infrastructure replacement is occurring and consumers are protected. We have the 7th lowest rates in the country, and the utility companies remain profitable as judged by their earnings and stock price.

2. What is your sense of the direction the committee and legislature should pursue that will best facilitate Missouri's economic health and growth?

   On the energy front, keeping rates as low as possible is key to attracting businesses. There are other avenues the legislature should use to grow our state. For example, I believe that education is key in attracting businesses. If we have the best trained workforce in the country, businesses will come.

3. Do you have any comments in support of, or opposition to, any particular regulatory model that was discussed in public hearing or to which you have been exposed otherwise?

   I would support reducing regulatory lag by reducing the time lapse during a rate case. Consumers spend a lot of time attempting to get data from the utilities. This is something they could do now to reduce lag themselves. I continue to be opposed to ISRS, decoupling, and formula rates.

4. What is your reasoning in support of your views?

   Any changes we consider must protect consumers. James Owens' testimony delineated some common sense proposals reducing regulatory lag while keeping the consumer protections in place. For this reason, I believe it is something that consumers can support. Formula rates, by practice, strips power from the PSC and reduces consumer protections. If you simply plug numbers into an equation to get a rate without looking at the whole picture, gold plating could occur because the incentive to overspend is present. ISRS bypasses the current process and gives utility companies the ability to bypass a rate case, and the surveillance reports under the program do not look at all relevant factors to determine if the ISRS is needed. Decoupling gives the utility a disincentive to control costs and look for savings. The utility can do virtually anything as it is still guaranteed to be made whole.

5. Do you have any specific questions that must be addressed in any compromise?

   Are all parties involved (including stakeholders) on board with the proposal? When I had a bill creating an "implementation impact report" for environmental changes being passed down by the EPA, I had to lay the bill over twice to hammer out a compromise with all stakeholders. All stakeholders need to agree on the best path forward before the legislature passes a bill. What is the financial impact on consumers? We want to protect our economy; data centers, grocery stores, mining operations, etc., list utilities as one of their highest costs of doing business. Our citizen constituents also struggle with the cost of utilities. Bottom line, can we afford a change in the ratemaking process.

6. May I distribute your written comments to other committee members if received prior to the hearing date?

   Yes.

Recommendations

After review and consideration of the testimony presented to the Committee, the Senate Interim Committee on Utility Regulation and Infrastructure Investment recommends the following:

1. Introduction and passage of legislation during the 2017 legislative session setting forth a new regulatory framework for electric utilities, including a performance-based ratemaking approach.

2. Inclusion of performance metrics within the performance-based ratemaking legislation that incentivizes grid modernization, reliability, and customer service.

3. Inclusion of an annual review process within the performance-based ratemaking legislation for setting electric utility rates by more closely matching revenues with costs, and allowing such review process to proceed based upon information provided by the utility's FERC Form 1 to the Public Service Commission.

4. Inclusion within the new regulatory framework for electric utilities the overt allowance of the Public Service Commission to verify the information contained in the electric utilities' FERC Form 1, and to set just and reasonable rates accordingly.

5. Requiring electric utilities, through the passage of legislation setting forth a new regulatory framework, to file a 5-year capital expenditure plan with such plan being updated on an annual basis.

6. Introduction and passage of legislation during the 2017 legislative session setting forth a new regulatory framework for gas, water, and sewer corporations, including a revenue stabilization mechanism with consumer protection provisions that set forth limitations in rate schedule increases.