BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Laclede Gas Company's	)	**File No. GR-2017-0215**
Request to Increase Its Revenues for Gas Service	)	Tariff No. YG-2017-0195
In the Matter of Laclede Gas Company d/b/a	)	**File No. GR-2017-0216**
Missouri Gas Energy's Request to Increase Its	)	Tariff No. YG-2017-0196
Revenues for Gas Service	)	

INITIAL POST-HEARING BRIEF OF

LACLEDE GAS COMPANY AND MISSOURI GAS ENERGY

JANUARY 9, 2018

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INITIAL POST-HEARING BRIEF OF
SPIRE MISSOURI INC.

Spire Missouri Inc. (f/k/a Laclede Gas Company and referred to herein as "Spire Missouri" or "Company") respectfully submits its Initial Post-Hearing Brief on behalf of its operating units Spire Missouri East (f/k/a Laclede Gas Company and referred to herein as "LAC") and Spire Missouri West (f/k/a Missouri Gas Energy and referred to herein as "MGE") in accordance with the Commission's *Order Adopting Procedural Schedule and Delegating Authority* issued in this matter on May 24, 2017. This Initial Post-Hearing Brief will address the remaining contested issues to be resolved by the Commission using the same numerical sequence appearing in the *Amended List of Issues, Order of Witnesses, Order of Cross-Examination, and Order of Opening Statements* filed by the Staff of the Commission ("Staff") on December 1, 2017.

INTRODUCTION/EXECUTIVE SUMMARY

It has been eight years since Spire Missouri last increased base gas rates for Missouri customers for anything other than the safety-related and mandated public improvement investments under the ISRS. The St. Louis-based company has been able to accomplish this laudable feat not through inaction, but by remaking the company from the ground up and producing value on an unprecedented scale for customers, shareholders and the Missouri economy. Over the last several years, the Company has replaced hundreds of miles of aging infrastructure (enough to traverse Missouri over two-and-a-half times), improved customer satisfaction measures, and improved almost every safety, operational and cost metric. (*See* Ex. 4, pp. 7-12, 16). Even if the modest increase requested in this current rate case is approved in full, a typical customer would still pay less than he or she did a decade ago for natural gas services. ((Ex. 4, p. 16, lines 1-2).

Spire Missouri has invested hundreds of millions of dollars to improve the service to Missouri customers. The Company has done so under the constructive framework established by the PSC in previous proceedings. If adopted by the Commission, the recommendations made by Staff, OPC and other parties in this case will represent a significant departure from that precedent and send a strong message that will negatively impact the Company's ability and desire to undertake similar efforts going forward.

Over the past four years, the Company's acquisitions, its redesigned mission and its renewed commitment to provide customers with upgraded infrastructure and exceptional experiences, have fundamentally transformed its business. On the whole, Spire's activities greatly benefit Missouri customers, all of which is borne out by the evidence presented in these cases. That evidence indicates that the Company has created approximately $70 million dollars in annual synergies and other savings as a result of the acquisitions and integration of MGE, Alagasco and EnergySouth over the past four years, all of which are already reflected in the cost of service being proposed for LAC and MGE in these cases. This includes nearly $50 million in ongoing savings from the acquisition and integration of LAC and MGE (Ex 7, p. 18), not including the significantly lower cost of long-term debt achieved with the financing of that transaction, and over $19 million in net savings from the acquisition of Alagasco and EnergySouth. (Ex. 9, p. 15; CEL-S2). Those savings would not have been possible had Spire not made the decision to grow and transform its utility businesses.

In addition to achieving these growth-oriented savings for its customers through acquisitions, the Company has also successfully undertaken other initiatives to reduce the cost of utility service for its customers. For example, in 2016, the Company began developing a pipeline lateral project in St. Peters, Missouri that would have enabled it to reduce its takes from one of its interstate pipeline suppliers. Rather than complete the project, however, the Company used it as leverage to achieve substantial transportation discounts from that pipeline supplier worth approximately $4.5 million per year. (Ex..29, p. 16). Over the next 12 years, these discounts will generate over $54 million in gas supply savings, every dollar of which will be passed through to customers through the PGA. (Ex. 30, p. 8).

Another example is the Company's $16 million purchase of its current Automated Meter Reading ("AMR") System from Landis & Gyr in July of 2017 (Ex. 65, pp. 1-2). As a result of this purchase, and the corresponding reduction in meter reading charges, LAC reduced its cost of service in this case by $1 million, even after consideration of offsetting maintenance costs and property taxes. (Ex. 65, p. 2, lines 12-13). Notably, the Company could have taken these savings to the bottom line rather than flow them through to its customers had it simply made the purchase a few months later after the true-up period expired.

Yet another example relates to the Company's focus on using existing tax laws to reduce its tax liability, utilizing the tax rules to lower the effective tax rate at MGE, and generating deferred taxes that lower the rate base being used to set rates for LAC and MGE by nearly $100 million on a combined basis, which equates to a revenue requirement reduction of $10 million, and reduces the effective tax rate at MGE by about 7%.

All of these measures, as well as others that you will read about on the following pages, have enabled the Company to fundamentally alter the historical rate trajectory of both LAC and MGE. Instead of utilities that routinely increased their rates by tens of millions of dollars every two or three years, LAC and MGE have now gone almost eight years with no increases other than those for safety-related and mandated public improvement investments made under the ISRS mechanism. These measures are also a primary reason why the Company is in a position in these cases to cover a multitude of significant cost increases for a relatively modest overall rate increase that, even if granted in full, would still leave rates for the average customer lower than they were 10 years ago.

Among others, these incremental cost increases include: (a) nearly eight years of inflationary increases in non-ISRS costs, (b) the $49 million in revenue requirement associated with ISRS investments made by LAC and MGE since their last rate cases (which customers are already paying in rates) (Tr. 532), (c) over $110 million in costs for two new enterprise-wide IT systems for LAC and MGE (Tr. 2195), and (d) approximately $200 million in regulatory assets that have been funded by the Company for many years and previously deferred for later recovery, which translate into significant new amortization costs relating to pensions, energy efficiency and low-income affordability programs, and other expenses. (Ex 4, pp. 15-16; Tr. 533 -535, Ex. 285, Acct. Sch. 02, p.1)

To its credit, the Company has been able to achieve these very favorable financial results for its customers while simultaneously improving the quality of the utility services they receive. As discussed by Steve Lindsey, the Company's President and Chief Operating Officer, by integrating the operations of LAC and MGE, leveraging the best practices of each operating unit, and incentivizing employee performance, the Company and its employees have increased the quality of the service received by customers in a number of key operational and safety areas. Among other service enhancements, the Company has managed to reduce the number of estimated bills it issues, improve its attainment rates for on-time customer appointments, and enhance call center performance in areas such as average speed of answer and abandoned call rate. (Exh. No. 4, pp. 10-11). It has also created a new web-based customer portal that provides customers with enhanced tools to better and more conveniently manage their utility bills and service. (Tr. 2197, line 20 to Tr. 2198, line 8). These, and other improvements, have also helped to drive the significant rise that MGE and LAC have recently received in their J.D. Power customer service rankings. (Tr. 581, line 15 – Tr. 582, line 3)

Perhaps most importantly, the Company and its employees have made significant improvements in the component of customer service that is the most critical one of all – namely safety. As Mr. Lindsey explained, the Company and its employees have successfully reduced the time required to respond to leaks on its system as well as the number of leaks that require a response by virtue of its accelerated replacement programs for cast iron and unprotected steel facilities. It has also decreased the quantity of third party hits to its pipeline facilities which, as the JJ's incident sadly demonstrated, are the major cause of natural gas incidents. (Ex. 4, pp. 7-9). In response to that incident, and in collaboration with the Commission's gas safety staff, the Company also spearheaded a statewide effort to better coordinate the efforts of utility personnel and first responders to address natural gas incidents when they occur. As part of that effort, the Company conducted four workshops throughout the state to gather and provide information on this important subject and ultimately provided the seed money for the Missouri Association of Natural Gas Operators ("MANGO") to make on-line training available to all emergency responders in Missouri on how to effectively and safely respond to natural gas emergencies. (*Id.*) Over this same time period, the Company also extended to MGE its commitment to accelerate the replacement of aging pipeline facilities that most impact public safety, transforming a cast iron replacement program from one that would have taken 80 years to complete under its previous schedule to one that is on pace to be completed in 20 years. (Ex.

4, p. 8). No party offered any witnesses in these cases to dispute the Company's assertions regarding its enhancements to customer service.

The Company and its employees are justifiably proud of this record of achievement on behalf of their customers. While the Company fully recognizes that other utilities strive to provide quality service at a reasonable price, it believes that the magnitude and nature of these customer benefits warrant additional consideration by the Commission as it decides how to resolve certain issues in this case.

The Company has incurred considerable costs to achieve the above noted benefits for customers, and undertook these initiatives under the expectation its prudently incurred costs would be appropriately recovered. Also, as noted above, these include ongoing inflationary pressures on its base business costs related to ISRS, investments in new IT systems, and amortization of regulatory assets. In addition, the Company has gone far beyond traditional activities and historic performance, and these efforts created considerable benefits for customers. A significant portion of these enhancements related to the growth in the customer base and spreading of costs; however, this was unlocked with employee efforts to transform the business by implementing a shared service model, undertaking a number of process improvements to effectuate best practices, enhancing service with a new customer portal and dispatching systems, and taking a more active role in the community through significant support and volunteer hours. Such "above and beyond" efforts and results were created through our holistic and balanced approach to employee incentives, both management and union, from executive to front line. These incentives were integral to creating customer benefits, including initiatives and goals that span customer service, safety, reliability and cost management. They were also critical to ensuring the Company would continue to have the financial capacity and capital to continue such customer benefits in the future by also focusing on the needs of its equity and debt investors for competitive returns. It is only appropriate that these costs are recovered in rates in the same manner as the tangible and significant benefits they helped achieve.

The significant customer benefits in the areas of safety, reliability, service and rates have been achieved by the Company through significant coordinated efforts and resources, as well as expense and investments into the business. These results deserve equitable, reasonable and fair recovery of the costs to achieve them, so as to promote progressive regulatory policies that encourage and support such favorable activities and outcomes both in these cases and going forward – in essence, balance the interests of the Company and its customers.

Attempts by other parties in these cases to disallow, write-off and undermine the positions taken by the Company in these cases is a violation of the productive ratemaking framework previously employed and strikes at the very heart of successful operating philosophy that the Company has used to create benefits for its customers. It would create roadblocks and negative consequences that would send the wrong message to Missouri utilities, move regulation in the wrong direction for the State, and threaten the prospects for such future enhancements for customers. A particularly egregious example of such an attempt can be found in the capital structure recommendations of Staff and OPC/MIEC in these cases to arbitrarily reduce the equity component of the Company's capital structure well below its actual equity component of 54.2%. As discussed below, these opportunistic and even punitive capital structure recommendations would remove tens of millions of dollars in needed revenue requirement from a Company cost of service that has already been substantially reduced as a result of the acquisition savings achieved by the Company. (Ex. 5, pp. 4-5). Although these recommendations from Staff and OPC rest on different and inherently conflicting theories, what they share in common is a deeply flawed attempt to inappropriately use these very same acquisition activities to derive an unrealistic equity component that is (a) some 700 to 800 basis points below the equity level that had traditionally been used by the Company and approved by the Commission for years prior to these acquisitions and (b) significantly below the average equity component reflected in the capital structures of the Company's peer utilities. The proposal by Staff to provide the Company with a clearly inadequate 1.5% return on its gas storage inventories and OPC's proposal to radically reduce the return received by the Company on its pension assets, prior to the Company finally beginning to recover on them, are two more examples of extreme recommendations that should likewise be rejected by the Commission.

Spire Missouri is moving in the right direction for customers, which is undisputed in these cases. The Company asks that the Commission be a champion for progress for utilities, their customers and our State. And, the Company respectfully asks the Commission to provide the policy decisions and leadership that move all stakeholders forward and allow the Company to continue to achieve the extraordinary outcomes that have been realized over the past eight years. The Company's requests in this regard are both modest and fully in keeping with the notion that the Commission, through its decisions and regulatory policies, should encourage these kinds of favorable outcomes. Specifically, the Company respectfully requests that the Commission:

- *Approve a Revenue Stabilization Mechanism ("RSM) or Modified Version of Staff's Weather Normalization Adjustment Rider ("WNAR").* As the evidence in this proceeding demonstrates, adoption of the Company's proposed RSM (or a properly modified version of Staff's WNAR) for the Residential and Small General Service Classes of LAC and MGE would help ensure that the Company does not over-recover or under-recover from customers its fixed distribution costs due to factors that are completely beyond its control. At the same time, it would provide the Company with greater flexibility to respond in a favorable and proactive manner to the frequently expressed desire by its customers at various public hearings (as well as the positions long-taken by OPC and other consumer advocates) for reductions in the Company's fixed monthly customer charge for residential service. If there was ever a time and a compelling policy rationale for approving such a mechanism, that time is now and that rationale has been provided in these cases.

- *Approve a Tracker for Environmental Compliance Costs.* The Commission should also approve the tracker that has been proposed by the Company for increases and decreases in environmental compliance costs. Like the RSM, recovery of such costs in between rate cases is explicitly authorized under Section 386.266 of Missouri law. The only distinction is that the tracking mechanism proposed by the Company is a more modest change to the regulatory process than what the law actually allows in that it defers these compliance costs until the next rate proceeding (instead of adjusting rates between cases to recover them) and would be limited solely to those environmental remediation costs relating to former manufactured gas plant sites.
- *Adopt the Company's proposal for developing performance metrics.* The Company also believes the Commission should explore ways of building upon the incentives that have helped the Company's employees to drive these positive outcomes for customers by adopting the Company's proposal for developing and implementing performance metrics. This better aligns the shareholder with the customer and the employee, helping to ensure everyone is "rowing in the same direction" and held accountable for service performance levels.

- *Adopt the Company's synergy sharing proposal*. Given the undisputed benefits that have been achieved for customers as a result of the Company's recent growth activities, the Commission should also adopt the Company's proposal to retain a modest share of the synergies created as a result of its parent company's acquisition of Alagasco and EnergySouth in 2014 and 2016. This proposal does not represent a radical departure from Commission policy. To the contrary, it is firmly grounded in the Commission's traditional practice of permitting utilities to retain a share of acquisition or merger synergies through regulatory lag. Moreover, it is amply justified by the fact that it is being offered in the context of acquisitions where the Company and its investors have shouldered the entire cost of these transaction and the resulting customer impacts are not speculative but now known to have provided substantial benefits to customers.

In the end, the Company, its employees and shareholders look, as they must, to the Commission to do the right and fair thing in these cases. The Company made a promise several years ago to transform its business in a way that would fundamentally improve the cost and quality of the services it provides its customers. It is a promise not typically made by businesses operating in a regulated environment. Whether through its acquisition activities, upgrading technology, redesigning business practices, or replacing aging facilities at a vastly accelerated pace, the Company, with the hard work of its employees and the significant financial support of its investors, has delivered on that promise. And as the undisputed evidence in these cases demonstrate, it has done so in a substantial and enduring way. Now it puts it trust in this Commission to reciprocate with the kind of enlightened regulatory response that is commensurate with what the Company has achieved.

ARGUMENT ON SPECIFIC ISSUES

I. LAC Only Issues

a. Forest Park Property

i. How should any gain resulting from the sale of the Forest Park property be treated for ratemaking purposes?

Executive Summary: As a matter of law and Commission practice, the Company is entitled to retain the $7.6 million gain resulting from the sale of its Forest Park property in 2014. While circumstances may occasionally arise where it is appropriate for a utility to share a gain on the sale of assets with its customers, those circumstances are decidedly not present in this instance for a variety of reasons. As discussed more fully below, these include the facts that: (1) the entire gain was related exclusively to the value of the land – an investment for which the Company has never been allowed to obtain a return of in its rates for regulated service; (2) the sale was one component of a very successful restructuring under which the Company managed, at a very minor net overall cost, to move its employees from aging, inefficient and even unsafe facilities to ones that were significantly more functional, efficient and accommodating to the Company's shared service model; (3) the sale facilitated the attraction of an IKEA store as part of the growth and development of the critical CORTEX entrepreneurial and science district in St. Louis City; (4) the Company more than offset the remaining rate base value of the Forest Park buildings with a capital contribution using the Forest Park relocation proceeds; and (5) the satellite office that the Staff claims replaced Forest Park service center is actually cheaper to own and operate than the Forest Park facilities would have been once they were rehabilitated.

Argument: The sale of the Forest Park facility, and the terms under which it was accomplished, were the result of a number of factors. As discussed by Company witness Susan Kopp, Spire's Director of Facilities, the Company had already decided to move the management personnel at Forest Park to 700 Market Street to facilitate its transition to a shared services model across a growing company. (Ex 43, p. 3). At around the same time, the Company had also begun a reorganization of its operations to reduce its operating districts from 3 to 2, thereby eliminating the need to maintain the remaining field personnel at the Forest Park service center. (*Id*.) Moving out of the Forest Park facilities had also become increasingly necessary because of serious physical and layout issues. Originally constructed in 1935, the facility had high maintenance and operating costs, inadequate secure parking space for utility vehicles, interior asbestos, roofing, plumbing, electric and other issues that would have required substantial investments to remediate. (*Id.*) Finally, the Forest Park facilities were located in the CORTEX redevelopment district. This created both an obstacle to investing any more money in the facility since it could be taken by CORTEX through eminent domain, as well as an opportunity to obtain a favorable price when CORTEX wanted the property to attract the first IKEA store to the St. Louis area. (*Id*.)

In the end, the Company was able to negotiate a sale price in 2014 that included: (a) a gain of approximately $7.6 million, excluding the $1.8 million undepreciated book value of the facilities and (b) an allowance of $5.7 million for relocation expenses. (Ex. No. 42 , p. 3). As shown by the appraisal report conducted in connection with the sale, the $7.6 million gain was related entirely to the value of the land, as the assets were actually worth less with the facilities on them. (Ex. 43, p. 3). After paying for various moving and relocation expenses associated with the restructuring of its facilities, the Company also used the remaining $1.95 million of the relocation proceeds received from the sale to purchase furniture and fixtures for its new office facilities at 700 and 800 Market Street – a capital contribution that avoided the need to add to the rate base underlying its cost of service in this proceeding. Additionally, the Company ultimately used a portion of the gain received from the sale to make a $1.5 million contribution to the City Arch Project in downtown St. Louis.

Notably, neither the Staff or OPC have suggested that the Company was in any way imprudent in its efforts to sell the Forest Park property and otherwise restructure its facilities to accommodate the objectives described above. Both parties have nevertheless proposed to seize a portion of the gains realized from the Forest Park sale and "share" them with ratepayers through various accounting adjustments, including as an offset to the cost of a satellite service center that the Company subsequently constructed on Manchester Avenue in St. Louis City. Such recommended treatment is both contrary to how the Commission has customarily handled such gains and completely unwarranted given the exceptional results that were achieved by the Company in restructuring its facilities.

Traditionally, the Commission has treated gains on the sale of utility assets *below* the line. *See* ***Re Kansas City Power and Light Company,*** Case Nos. EO–85–185 and EO–85–224; 75 P.U.R.4th 1 (1986), citing ***Re Missouri Cites Water Co***.*,* 26 Mo PSC NS 1 (1983) and ***Re Associated Nat. Gas Co.****,* 26 Mo PSC NS 237, 55 PUR4th 702 (1983). Moreover, the Commission has found this treatment to be particularly appropriate where, as here, the transaction involves the sale of non-depreciable property such a land since, as the Commission observed in the ***Kansas City Power and Light*** case**,** the "the shareholder has not received a multiple recovery of the investment through depreciation and again through the sale of the property. ***Kansas City Power and Light, supra****,* at 29.

While, as Staff has noted, the Commission has suggested that there might be some circumstances where a sharing of such gains with ratepayers would be appropriate*, see* ***Missouri Cities Water Co.****,* ***supra,*** such circumstances do not exist in this case. And neither Staff nor OPC have cited any that withstand scrutiny.

For example, both Staff and OPC have simply ignored the fact that the gain in this instance related to a sale of non-depreciable land, which makes it particularly unsuited to the kind of treatment they are proposing. OPC's argument that permitting the Company to retain these gains is inappropriate because it is still earning a return on the $1.8 million undepreciated book value of the Forest Park facilities at the time it was sold is equally baseless. As Company witness Glenn Buck pointed out in his affidavit, (Exh. No. 64), any revenue requirement impact associated with the $1.8 million has been more than offset by the $1.95 million capital contribution that the Company made from the relocation proceeds of the Forest Park sale to purchase furniture and fixtures for the Company's new office facilities at 700 and 800 Market Street. In fact, when rates in this proceeding become effective, the Company will only be earning a return on the remaining $1.8 million book value of the Forest Park, but nothing for any related depreciation. In contrast, customers will be avoiding the costs of providing both a return on and a return of (i.e. depreciation) for the $1.95 million capital contribution made by the Company for office furniture and fixtures, which results in a lower revenue requirement than would have been the case for the assets LAC contributed. In short, the Company has already addressed this concern in a more than sufficient manner by how it used the Forest Park proceeds. It is a complete non-issue, as is Staff's misguided efforts to seek customer sharing of funds LAC received to offset moving expenses outside the test period, and with which LAC contributed offsets to reduce costs related to necessary capital investments.

The Staff has suggested that assigning a part of the gain to ratepayers is appropriate because the Forest Park operations center was replaced by what it claims was the more expensive Manchester satellite service center facility. Again, this is a wholly inaccurate assertion for two reasons. First, as Company witness Kopp testified, the Manchester satellite facility was never intended to be and, in fact, was not a replacement for the Forest Park facility. (Ex. 42, p. Ex. No. 43, p. 2, lines 10-12). Second, the Staff is simply incorrect in asserting that the Manchester satellite facilities is more expensive to own and operate than the Forest Park facility would have been, especially if the necessary costs required to rehabilitate and make it suitable for use in the future had been incurred. In claiming otherwise, the Staff simply did not make a comprehensive analysis of the relative property tax, utilities, maintenance expenses and upgrade costs of the two facilities. Ms. Kopp did that kind of analysis and it demonstrated that the Forest Park facility would have actually cost over $900,000 more to own and operate from 2017 to 2020 than the Manchester facility will. (Ex. 43, Schedule SMK-SI). Again, while the Company does not consider the Manchester facility to be a replacement for Forest Park, Staff's theory that the Company should share the gains on the Forest Park property because leaving that facility and constructing the Manchester facility resulted in increased costs for the Company simply has no basis in fact.

Also missing from the Staff's analysis for why ratepayers should receive a share of proceeds that were realized by the Company more than a year and half before the test year in this case, is any appreciation for what the Company was able to achieve through the restructuring of its facilities, including Forest Park. As Ms. Kopp testified, the Forest Park sale was part of any overall restructuring of the Company's facilities that permitted it to move out of aging and unsuitable facilities and relocate to far more functional facilities that are more conducive to the effective implementation of the share service strategy that has enabled the Company to generate tens of millions of dollars in savings for its customers. Staff's analysis also gives no recognition to the significant contributions to the St. Louis community that were made possible by this restructuring and how the Company handle the resulting proceedings, including making it possible to add an a very attractive retail institution to the critical CORTEX development district, save and refurbish an iconic office building in the heart of downtown St. Louis and make a significant financial contribution to the Arch revitalization project. Notably, all of these benefits were achieved by the Company while still upgrading the facilities used to serve customers at a very modest cost. (Ex. 42, pp. 3 to 13). In light of these considerations, there is simply no basis for either Staff's or OPC efforts to take any portion of these gains away from the Company.

ii. How should the relocation proceeds from the sale of the Forest Park property, other than proceeds used for relocation purposes or contributed to capital for the benefit of customers, be treated for ratemaking purposes?

Executive Summary: Because *all* of the relocation proceeds from the Forest Park sale were either spent on relocation expenses incurred by the Company in connection with the restructuring of its facilities or were contributed to capital through the purchase of office furniture that would have other been paid for by customers, there should be no question that the Company is entitled to retain these proceeds. Consistent with Commission ratemaking practices, such a result is also mandated by the fact that such proceeds were received well before the test year in this proceeding, were not subject to any deferral order and represented a one-time, non-recurring event.

Argument: It is exceedingly difficult to understand why the relocation proceeds received from the sale of the Forest Park property are even an issue in this proceeding. As Company witness Kopp explained, all but $1.95 million of the approximate $5.6 million in relocation proceeds were used to relocate employees and pay for other, related expenses, such as archiving documents and moving equipment. (Ex. No. 42, Kopp Rebuttal, pp. 8-9; , Ex. 43, p. 2; Tr. 1602).

Moreover, during the evidentiary hearing, it became clear that the relocation proceeds were, in fact, used for these purposes. Although Staff witness Kunst implied in his surrebuttal testimony that he had not been given information showing how the proceeds were used (except for the portion that was used to make a capital contribution) (Ex. 251, p. 6, line 19 – p. 7, line

2), it became clear on cross examination that Mr. Kunst had been provided with a massive spreadsheet with hundreds of entries showing where every dime of these proceeds was spent. (Tr. 1639, lines 12-21). Mr. Kunst also had memoranda from the Company's outside auditors verifying the use of these proceedings for various relocation, document retention and moving expenses associated with the Company's facility restructuring. (Tr. 1638-39)

In the end, it appears that Mr. Kunst and OPC witness Hyneman's only complaint was that such expenditures were used for relocation and expenses associated with other facilities that were part of the Company's restructuring effort. There is simply no principle of law or any policy rationale, however, that would somehow bind the Company to using these relocation proceeds, which LAC negotiated for above and beyond the sale price, solely to move employees out of Forest Park or risk forfeiting them. Nor is it in any way permissible, especially in the absence of an approved deferral, for the Staff and OPC to reach back to a period well before the test year in these cases, and selectively grab this one-time, non-recurring portion of proceeds received by the Company. The fact is that the proceeds were used for legitimate relocation expenses, and contributions to capital, so ratepayers were spared of any obligation to pay such expenses (whether as a transition cost or otherwise), because of the Company's actions. There is accordingly no justification whatsoever for Staff's or OPC's attempt to reach back to a period well before the test year and seize these one-time proceeds.

II. <u>MGE Only Issues</u>

a. Kansas Property Tax

i. What is the appropriate amount of Kansas property tax expense to include in MGE's base rates?

Executive Summary: Over the past several years, Kansas property taxes have varied by a range of $900,000, and have been handled by a property tax tracker, which has permitted customers to pay the actual cost of this item. If the tracker is not continued, ongoing Kansas property taxes of $1.7 million per year should be included in rates.

ii. Should the tracker for Kansas property tax expense be continued?

Executive Summary: Yes. Given the uncertainty and history of variability in the amount of this expense item, the Company agrees with Staff that the current tracker authorized for this expense should be continued with a Kansas property tax amount of $1.454 million reflected in the rates and used as the benchmark for measuring any over or under-recovery of such expense.

Argument: At the time of the filing its direct case, the Company was collecting in rates $1.6 million for the amortization of past property taxes that were paid by MGE for gas stored in Kansas, but not included in rates, as well as $1.4 million for the estimated amount of current yearly property taxes on such gas inventories (Ex.29, Noack Rebuttal, p. 5). As explained by Mr. Noack an adjustment should be made to reflect the fact the past property taxes paid but not included in rates will be fully amortized in June 2019 or just a little more than a year after rates from this case go into effect. Taking into consideration that the current level of taxes in rates of $1.4 million is also being tracked, the Company has collected approximately $500,000 more in rates than what has been paid which, when included with the past taxes being amortized, will result in the balance being fully amortized sooner than June 2019. (*Id*. at 5-6).

Kansas property tax is based on one day of pricing and the volumes in storage on that day on what is probably the world's most volatilely priced commodity (i.e. natural gas) and subject to efforts by a number of taxing jurisdictions that have shown the penchant for increasing tax rates. $1.454MM is a reasonable price relative to the expected expense of $1.7MM for 2017 and should help ensure a customer benefit, with the Company tracking the volatility of costs until future recognition in the next rate case. Given the volatility of the Kansas property tax expense, the continuation of the Kansas property tax tracker is reasonable and appropriate.

MGE witness Michael Noack recommended that the Commission authorize an annual level of Kansas property taxes of $1,691,513 if the existing tracker is discontinued or, as an alternative, include an annualized level of property taxes based on a three (3) or four (4) year period and continue the existing tracker. (Ex. 29, Noack Rebuttal, pp. 6-7).

Staff initially proposed to take the balance of the paid but unrecovered taxes along with any tracked overpayment of taxes since the 2014 rate case and amortize that remaining balance over a new 5-year period. In addition to that amortization, Staff proposed to include in rates $1,122,514 for current taxes without continuing the tracker which the Company have now. The resulting total adjustment is a reduction of $1,589,056. (Ex., Noack Rebuttal, p. 6).

However, Staff re-evaluated its original position on this issue in the surrebuttal testimony of Karen Lyons who explains at some length the reasons for Staff’s change of position. (Ex. 252, Lyons Surrebuttal, pp. 2-7). Staff is now recommending the establishment of a normalized level of Kansas property taxes of $1,454,069, and the continuation of a Kansas property tax tracker in this proceeding:

Based on 2017 Kansas tax statements received subsequent to Staffs direct filing, Staff reevaluated MGE's historical Kansas property taxes paid for the period of 2009-2016 and what MGE will likely pay in 2017. The level of Kansas property taxes recommended by Staff at the time of its direct filing, $1.1 million, is not reflective of what MGE will incur on an annual basis in the near future for these taxes. Although the 2017 Kansas property taxes owed by MGE will likely be higher than the last several years, Mr. Noack's recommendation of approximately $1.6 million is not reflective of what MGE has incurred on an annual basis. The variability of the natural gas storage volumes and gas price based on one day used in the assessment by the State of Kansas contributed to the increase in these taxes in 2017. Consequently, Staff recommends the Commission approve Staffs recommended normalized level of Kansas property taxes of $1,454,069 and continuation of the existing tracker. (Ex. 252, Lyons Surrebuttal, p. 7).

LAC/MGE believe Staff's revised recommendation is reasonable, and should be accepted by the Commission.

III. LAC-MGE Common Issues

a. Cost of Capital

i. Return on Common Equity – What is the appropriate return on common equity to be used to determine the rate of return?

Executive Summary: In this proceeding, the Company is requesting a 10.35% ROE, utilizing the actual capital structure of Spire Missouri, the regulated public utility, taking into account its business risk as a smaller public utility. Staff is recommending an ROE of 9.25% within the range of 9.00 to 9.50. (Ex. 204, Staff Cost of Service Report, p. 7) OPC/MIEC is recommending an ROE of 9.20% in the range of 8.90% to 9.40%. (Ex. 407, Gorman Direct, p. 2) However, as discussed in more detail below, the Commission must reject the recommendations of Staff and OPC/MIEC and rely instead upon the recommendations of the expert with the most reasonable ROE range that is based upon generally accepted and reliable estimates of the returns that investors expect. The most prominent among those expert opinions in this proceeding is that of Spire Missouri witness Pauline Ahern who has testified before this Commission on several occasions. She recommends that the Commission adopt a 10.0%

ROE before adjustment for floatation costs and the business risk of a smaller utility. (Ex. 38, Ahern Direct, pp. 5, 52-53). After adjustment for floatation costs and business risk, Ms. Ahern is recommending a common equity return of 10.35%. (Ex. 38, Ahern Direct, p. 53).

Staff witness David Murray testified that he believed the actual market cost of common equity for Spire Missouri was in the range of 6.90% to 7.70%. (Ex. 204, Staff Cost of Service Report, p. 7, 39) (Tr. 1290) which is 100 basis points lower than what Staff recommended in the most recent natural gas case involving Liberty Utilities. (Tr. 1290-91). According to the Commission's findings of fact in the Liberty Utilities case, Staff's midpoint recommendation in that case (8.7%) was more than 60 basis points lower than any return on equity at any state Commission in at least 30 years. (Tr. 1290-91). (Ex. 59, Report and Order, Case No. GR-2014-0152, p. 19). Mr. Murray testified "without a doubt" (Tr. 1295) that such a low range of 6.7% to 7.7% had not been found to be reasonable by any state agency for many years as an allowable return. (Tr. 1292). Instead of recommending the ROE range that he believed to be the actual cost of common equity for Spire Missouri, Mr. Murray looked at the ROE that the Commission authorized in a KCP&L rate case, and adjusted it downward for his perceived risk differential between natural gas companies and vertically integrated electric companies. (Tr. 1300-01) For the reasons stated below, this novel approach should be rejected by the Commission, as it has rejected other Staff ROE recommendations in the past.

OPC/MIEC jointly sponsored the testimony of Mr. Michael Gorman. Based upon his analysis, Gorman recommended an ROE in the range of 8.90% to 9.40%. (Ex. 407, Gorman Direct, p. 2). For the reasons stated below, Mr. Gorman's recommendations should not be adopted without adjustment by the Commission.

Argument:

Governing Legal Principles

As the Commission has recognized many times in the past, the United States Supreme Court established requirements for determining the reasonable rate of return in ***Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia***, 262 U.S. 679, 692 (1923) ("***Bluefield***") and ***Federal Power Comm'n v. Hope Natural Gas Co.***, 320 U.S. 591, 603 (1944) ("*Hope*"). In short, the fixing of "just and reasonable" rates involves a balancing of investor and consumer interests. ***Hope***, 320 U.S. at 603. "What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts." ***Bluefield***, 262 U.S. at 692.

A reasonable rate of return is one that closely approximates the profits upon capital invested in other undertakings where the risk involved and other conditions are similar. ***Bluefield***, 262 U.S. at 689-90. "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties . . . ." ***Bluefield***, 262 U.S. at 692.

In the *Report & Order* in ***Re: Kansas City Power & Light Company***, Case No. ER-2010-0355 (April 12, 2011), pp. 120-24, the Commission described its role in determining the return on equity as follows:

> 32. The Commission must draw primary guidance in the evaluation of the expert testimony from the Supreme Court's Hope and Bluefield decisions. Pursuant to those decisions, returns for GPE's shareholders must be commensurate with returns in other enterprises with corresponding risks. Just and reasonable rates must include revenue sufficient to cover operating expenses, service debt and pay a dividend commensurate with the risk involved. The language of Hope and Bluefield unmistakably requires a

> comparative method, based on a quantification of risk.
>
> 33. Investor expectations are not the sole determiners of ROE under Hope and Bluefield; we must also look to the performance of other companies that are similar to KCP&L in terms of risk. Hope and Bluefield also expressly refer to objective measures. The allowed return must be sufficient to ensure confidence in the financial integrity of the company in order to maintain its credit and attract necessary capital. By referring to confidence, the Court again emphasized risk.
>
> 34. The Commission cannot simply find a rate of return on equity that is "correct"; a "correct" rate does not exist. However, there are some numbers that the Commission can use as guideposts in establishing an appropriate return on equity. The Commission stated that it does not believe that its return on equity finding should "unthinkingly mirror the national average." Nevertheless, the national average is an indicator of the capital market in which MGE will have to compete for necessary capital.
>
> 35. The Commission has described a "zone of reasonableness" extending from 100 basis points above to 100 basis points below the recent national average of awarded ROEs to help the Commission evaluate ROE recommendations. Because the evidence shows the recent national average ROE for electric utilities is 10.34%, that "zone of reasonableness" for this case is 9.34% to 11.34%. (*footnotes omitted*)

The Commission should follow a similar approach for the establishment of Spire Missouri's return on equity in this proceeding and adopt the recommendations of the Company related to cost of capital issues. As Staff witness David Murray confirmed in cross-examination (Tr. 1293-94), the Company's recommendation ROE of 10.35% is within the current zone of reasonableness, based upon national average authorized returns (9.5% for the first six months of 2017; and updated to 9.89% for the calendar year of 2017) (Tr. 1187)(Ex. 40, Ahern Surrebuttal, p. 40), implying an upper range of 9.89% to 10.89% using the zone of reasonableness approach.

<u>The Company's Recommendation: Witness Pauline Ahern</u>

Spire Missouri witness Pauline Ahern is a well-qualified economic and financial consultant who has provided testimony on strategic and financial matters before thirty-one state regulatory commissions in the United States and Canada. Ms. Ahern holds a Bachelor of Arts degree with honors in Economics from Clark University, Worcester, MA and a Master of Business Administration with high honors and a concentration in finance from Rutgers University.

Ms. Ahern has served as a consultant for investor-owned and municipal utilities and authorities for nearly 31 years. As a Certified Rate of Return Analyst (CRRA), she has extensive experience in rate of return analyses, including the development of ratemaking capital structure ratios, senior capital cost rates, and the cost rate of common equity for regulated public utilities. She has testified as an expert witness before 31 regulatory commissions in the U.S. and Canada. A summary of Ms. Ahern's professional and educational background, including an extensive list of testimony in prior proceedings, is included in Appendix A to her Direct Testimony. (Ex 38, Ahern Direct, Appendix A, Page A-1 through Page A-6).

To develop her cost of equity recommendation, Ms. Ahern conducted several standard analyses – applied several well-recognized cost of common equity models (i.e., the Discounted Cash Flow ("DCF"), the Risk Premium Model ("RPM") and the Capital Asset Pricing Model ("CAPM") to the market data of the Natural Gas Proxy Group as well as a Non-Price Regulated Proxy Group. (Ex. 38, Ahern Direct, pp. 3-4; 9-34)

The results of Ms. Ahern's analyses, set forth on the table below, support her recommended her ROE point recommendation of 10.35%. (Ex. 38, Ahern Direct, pp. 35):

Summary of Common Equity Cost Rate

Natural Gas Proxy Group	
Discounted Cash Flow Model ("DCF")	8.68%[1]

[1] As Ms. Ahern explained, the application of the DCF model understates the required return on common equity by nearly 490 basis points due to the currently significantly high market-to-book ratios. Accordingly, the results of that model should be given only very limited weight in deriving a reasonable return on equity in this proceeding. (Ex. 38, Ahern Direct, p. 5 fn.3).

Risk Premium Model ("RPM")	10.57%
Capital Asset Pricing Model ("CAPM")	9.11%
Non-Price Regulated Proxy Group Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Cos.	10.45%
Common Equity Cost Rate Before Adjustment	10.00%
Flotation Risk Adjustment	0.16%
Business Risk Adjustment	0.20%
Common Equity Cost Rate After Adjustment	10.36%
Recommended Common Equity Cost Rate	10.35%

She also calculated the common equity cost rates using the DCF, RPM, and CAPM for the Non-Price Regulated Proxy Group. As shown on her Schedule PMA-D7, the average and median DCF-based cost rates for the Non-Price Regulated Proxy Group is 11.86%. (Ex. 38, Ahern Direct, p. 44). The RPM and CAPM applied to the Non-Price Regulated Group are 10.30% and 9.62%, respectively. Based upon these results, Ms. Ahern relied upon the average of the mean and median results of the three models, which is 10.45% for the Non-Price Regulated Proxy Group. (Ex. 38, Ahern Direct, p. 46).

Based upon all of the evidence, Ms. Ahern concluded that Spire Missouri's common equity cost rate is 10.00% after applying the various models to the Natural Gas Proxy Group and to the Non-Price Regulated proxy group before any adjustments for floatation costs and for Spire Missouri's greater business risk due to its smaller size relative to the Natural Gas Proxy Group. (Ex. 38, Ahern Direct, p. 46)

Finally, Ms. Ahern compared Spire Missouri to the proxy group of natural gas companies based on the following factors: (1) the relatively small size of Spire Missouri; and (2) flotation costs. (Ex. 38, Ahern Direct, pp. 46) Ms. Ahern found that Spire Missouri is significantly smaller than the proxy group, both in terms of number of customers and annual revenues. Ms. Ahern considered the small size of Company in her assessment of business risks in order and determined that an adjustment of 0.20% was appropriate to reflect the greater business risk of the Company due to its smaller size relative to the Natural Gas Proxy Group. (Ex. 38, Ahern Direct, p. 51-52). With regard to floatation costs, Ms. Ahern found that an adjustment of 0.16 percent (i.e., 16 basis points) reasonably represents floatation costs for the Company. (Ex. 38, Ahern Direct, pp. 47-49). Without such an adjustment, there is no way for the Company to recover these legitimate costs under the current regulatory model used in Missouri. (Ex. 38, Ahern Direct, pp. 48-50) Based upon this analysis, Ms. Ahern concluded that the reasonable ROE for Spire Missouri is 10.35%. (Ex. 38, Ahern Direct, p. 47).

Staff's Recommendation: Witness David Murray

David Murray is currently the Utility Regulatory Manager of the Financial Analysis Unit, Commission Staff Division for the Commission. In May 1995, Mr. Murray earned a Bachelor of Science degree in Business Administration with an emphasis in Finance and Banking, and Real Estate from the University of Missouri-Columbia. He also earned a Masters in Business Administration from Lincoln University in December 2003. Mr. Murray has never worked for another regulatory commission, public utility, or financial institution. (Tr. 1279)

In this proceeding, Mr. Murray testified that he believes the cost of equity for LAC and MGE "is presently in the range of 6.90% to 7.70%." (Ex. 203, Staff Cost of Service Report, p. 7) However, he quickly walked away from this range, and instead recommended an ROE range of 9.00% to 9.50, based upon his perceived risk differential between natural gas companies and KCP&L. (Ex. 203, Staff Cost of Service Report, p. 45).

Rearview Mirror Analysis of Staff

Staff's analysis is less credible than Spire Missouri's evidence. Staff witness Murray rejected his own conclusion of an appropriate range of common equity cost rate for the Company of 6.90% to 7.70%, implicitly recognizing that this range is totally inadequate and would provide an insufficient achieved return on the book common equity of the Company. Instead he recommended a range of common equity cost rate of 9.00%-9.50, with a midpoint of 9.25%, based upon his review analysis of authorized returns of common equity for Ameren Missouri and KCP&L. (Ex. 203, Staff Cost of Service Report, p. 8). Staff's approach is essentially a rearview mirror approach looking back at economic conditions that existed in 2014 and 2015 (test years in the last Ameren and KCP&L rate cases), and not using the improved economic and interest rate data to review the current market conditions for the year the rates in this case will be in effect--2018. In other words, given the improving economy and increasing Federal Reserve interest rates, the authorized ROEs should be higher than in 2014-15, as recommended by Ms. Ahern.

As explained by Ms. Ahern, Staff's proposed range (and Mr. Gorman's) is below the level of earnings expected by *Value Line* for the companies in his Natural Gas Distribution Group for which Value Line publishes a projected return on common equity for the years 2020-2022. The latest (September 1, 2017) Value Line Ratings & Reports (Standard Edition) for the companies in Mr. Murray's Natural Gas Proxy Group are shown on pages 2-8 of in Ms. Ahern's Schedule PMA-R12. Page 1 of Schedule PMA-R12 indicates that *Value Line* expects the companies in Mr. Murray's Natural Gas Proxy Group to earn an average 9.90% return on year-end book common equity over the next 3-5 years. An opportunity to earn a range of return on book common equity of either Mr. Murray's recommended range of 9.00% - 9.50%, is inadequate in comparison with the average expected return on book common equity of the Natural Gas Proxy Group of 9.90%. Thus, Mr. Murray's recommendation is inconsistent with the comparability of returns standard enunciated in the *Hope* decision. Staff's recommended common equity cost rate range should therefore be rejected by the Commission. (Ex. 39, Ahern Rebuttal, p. 40.).

In addition, Mr. Murray (as well as Mr. Gorman) have failed to reflect an adjustment to reflect the relative risk of the Company due its smaller size relative to the natural gas company in the Natural Gas Proxy Group, and floatation costs. (Id. at 41) After Ms. Ahern corrected Staff's DCF, CAPM, and RPM for errors discussed in her rebuttal testimony, Staff's DCF, CAPM, and RPM is 9.34%, 9.71%, and 9.71%, respectively, averaging 9.46%. With the addition of floatation costs and a business risk adjustment, the result would be 10.02%. (Ex. 39, Ahern Rebuttal, p. 47).

Based upon this analysis, the Commission should conclude that Staff's proposed range of 9.00%-9.50% is inadequate and unreasonable.

Flaws in OPC/MIEC Analysis

Ms. Ahern also pointed out numerous technical flaws in OPC/MIEC witness Mr. Michael Gorman's analysis. (Ex. 39, Ahern Rebuttal, pp. 47-70). [2] After Ms. Ahern

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[2] 1) Mr. Gorman has provided no empirical evidence that in the third stage of a multi-state DCF analysis any company, especially relative stable and mature utility companies, would grow at the average growth rate of the U.S. economy. (Id. 50);
2) His DCF results are understated at this time because the simplified or constant-growth DCF mode has a tendency to mis-specify the investor required common equity return rate when the market value of common stock differs significantly from its book value, because it assumes a market-to-book ratio of one, overstating investor's required return rate when the market value exceeds the book value. (Id. at 50-58);
3) With regard to Mr. Gorman's Equity Risk Premium analysis, Ms. Ahern expressed the following concerns:
a) The use of the 1986-mid-2017 time period is highly suspect and unlikely to be representative of long-term trends in market data. (Id. at 59-60);
b) His method and recommendation ignore an important relationship that the equity risk premium has a strong negative correlation to the level of interest rates. (Id. at 59);
c) He improperly mismatched the application of the U.S. Treasury Bond and public utility bond methods. (Id.)
4) With regard to Mr. Gorman's CAPM analysis, Ms. Ahern identified the following flaws:
a) His choice of a recent historical yield on 30-year U.S. Treasury bond as the risk-free rate;
b) His use of an historical market equity risk premium which is incorrectly derived;
c) His failure to also include a forecasted market equity risk premium; and,

corrected OPC/MIEC's DCF, CAPM, and RPM for errors discussed in her rebuttal testimony, OPC/MIEC's DCF, CAPM, and RPM is 8.90%, 9.47%, and 10.21%, respectively. A range of indicated common equity cost rates based upon Mr. Gorman's two proxy groups is 8.90% - 10.21%, averaging 9.53%. (Id. at 70-71). However, these cost rates are still understated because they do not reflect flotation costs and additional risk of the Company due to its smaller size. (Id. at 71)

With a business risk adjustment of 20 basis points, due to Spire Missouri's smaller size, and a floatation cost adjustment of 0.16%, Mr. Gorman's corrected 9.53% common equity cost rates would be 9.89% (9.89%= 9.53% +0.16% +0.20%). (Id. at 74-75).

<u>Business Risk Adjustment Should Be Included</u>

Empirical evidence demonstrates that there is increased risk due to the small size of Spire Missouri compared to the Natural Gas Proxy Group used by Ms. Ahern, Staff and OPC/MIEC. Spire Missouri's estimated market capitalization of $2.5 billion is lower than the average market capitalization of the Natural Gas Proxy Group, $3.2 billion, or 1.3 times greater than Spire Missouri's as of January 31. 2017. (Ex. 37, Ahern Direct, p. 50-53; Ex. 38, Ahern Rebuttal, pp. 42-47, 72-75). The Company has greater relative business risk, because, all else being equal, size has a bearing on risk. Because investors demand a higher return as compensation for assuming greater risk, this greater relative risk of Spire Missouri must be reflected in the recommended cost of common equity derived from the market data of the less business risky Natural Gas Proxy Group. Ms. Ahern has quantified this business risk differential as 0.20% which should be reflected in Spire Missouri's authorized ROE in

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d) His failure to apply the Empirical Capital Asset Pricing Model ("ECAPM") to account for the fact that the Security Market Line ("SML") as described by the traditional CAPM is not as steeply sloped as the predicted SML. (Id. at 67-70).

this proceeding.

Flotation Costs Should Be Reflected
<u>in the ROE Authorized in this Proceeding</u>

As noted by Ms. Ahern, there is no mechanism through which such costs can be captured in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate to reflect the costs associated with the sale of new issuances of common stock. These costs include market pressure and the essential costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate even when there has not been an issuance during the test year nor in the absence of an expected imminent issuance of additional shares of common stock.

The various cost of common equity models (DCF, RPM and CAPM) assume no transaction costs, and therefore flotation costs are not reflected in the results of the application of these models. The Commission should therefore include floatation costs in the authorized ROE in this proceeding.

<u>ROEs Authorized by Other Public Utility Commissions</u>

This Commission has always compared its ROE analysis with those of other commissions to make certain that it was not out of the mainstream. Although it does not "slavishly follow the national average in awarding a return on equity"[3] or "unthinkingly mirror the national average,"[4] the Commission has concluded that "the national average is an indicator of the capital market" in which a utility "will have to compete for necessary capital." See *Report and Order*, Re Kansas City Power & Light Co., Case No. ER-2010-0355, p. 122 (Apr. 12, 2011); *Report and Order***,** Re KCP&L Greater Mo. Operations Co., Case No. ER-2010- 0356, p. 148 (May 4, 2011).

The United States Supreme Court has advised commissions to examine the returns being earned by companies "at the same time and in the same general part of the country" as the utility appearing before it. *Bluefield*, 262 U.S. at 692. According to Staff's direct case, the averaged authorized return on equity in the first half of 2017 for natural gas and electric utility companies were 9.5 percent) (Staff Ex. 203, Staff Cost of Service Report, p. 40), and updated to 9.89 percent (based on decisions in the last part of 2017)(Tr. 1189)(Ex. 40, Ahern Surrebuttal, p. 40).

The Commission generally sets the zone of reasonableness at 100 basis points above and below the national average ROE authorized for similarly-situated utilities. See *State ex rel. Public Counsel v. PSC*, 274 S.W.3d 569, 574 (Mo. App. W.D. 2009). This methodology for setting the zone of reasonableness was upheld by the Missouri Court of Appeals as recently as 2012, holding as reasonable an ROE that "falls within the zone of reasonableness for returns on equity based on the national average authorized return on equity for gas utilities." ***State ex rel. Office of the Public Counsel v. PSC***, 367 S.W.3d 91, 110-11 (Mo. App. S.D. 2012).

The Commission should adopt the Company's recommended return on equity in the range of 10.35 percent which is clearly within the zone of reasonableness. Given the

[3] *Report and Order*, In re Union Elec. Co., Case No. ER-2011-0028, p. 67 (July 13, 2011).
[4] *Report and Order*, Re Missouri Gas Energy, Case No. GR-2004-0209, p. 19 (September 21, 2004).

small size and business risk of Spire Missouri, this ROE authorization is appropriate for purposes of this case.

ii. Capital Structure: What capital structure should be used to determine the rate of return?

Executive Summary: Spire Missouri's stand-alone capital structure should be used for purposes of setting rates in this proceeding. That capital structure, which is comprised of an equity component of 54.2% and debt component of 45.8%, is fully in line with the capital structure that has long been used by the Company (and approved by the Commission) for setting rates in Missouri, including for many years prior the acquisitions of MGE, Alagasco and EnergySouth. It is also in line with the equity components of the capital structures employed by the Company's peer utilities. In contrast, the capital structures recommended by Staff and OPC/MIEC contain equity components of 45.56%and 47.20%, respectively. As discussed below, these capital structure recommendations, which rest on different and inherently conflicting theories, are wildly inconsistent with the historical norms for the Company as well as the capital structures of its peer utilities. There is simply no justification for arbitrarily denying the Company tens of millions of dollars in revenue requirement based on such opportunistic recommendations, particularly where they are so obviously outside the mainstream of utility capitalizations that this and other commissions have found to be a reasonable. They should accordingly be rejected by the Commission.

Argument: The capital structure issue is an important real world financial issue since the use of a consolidated parent capital structure for ratemaking purposes may substantially affect the ability of the public utility itself to earn its authorized rate of return on investment. In practice, the capital structure should enable the Company to maintain or enhance its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions. (Ex. 36, Hevert Surrebuttal, pp. 18-19). For example, if the equity ratio used for ratemaking purposes is lower than the actual equity ratio of the public utility, it may make it substantially more difficult for the public utility to earn its authorized return on equity.

The capital structure relates to financial risk, which is a function of the percentage of debt relative to equity (that relationship is often referred to as "financial leverage"). As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk that cash flows may not be sufficient to meet those obligations on a timely basis. Consequently, as the degree of financial leverage increases, the risk of financial distress (i.e. financial risk) also increases. Since the capital structure can affect the subject company's overall level of risk, it is an important consideration in establishing a just and reasonable rate of return. (Ex. 37, Rasche Surrebuttal, pp. 6-7).

The factors typically considered relative to the use of a regulated subsidiary's actual capital structure or a parent holding company's consolidated capital structure for ratemaking are provided by David C. Parcell in *The Cost of Capital – A Practitioner's Guide* ("CRRA Guide") prepared for SURFA and provided as the study guide to candidates for SURFA's Certified Rate of Return Certification Examination, The CRRA Guide notes that these factors or "considerations" will "help determine whether the utility vs parent capital structure is appropriate." They are:

1) Whether the subsidiary utility obtains all of its capital from its parent, or issues its own debt and preferred stock;

2) Whether the parent guarantees any of the securities issued by the subsidiary;

3) Whether the subsidiary's capital structure is independent of its parent (i.e., existence of double leverage, absence of proper relationship between risk and leverage of

utility and non-utility subsidiaries; and

4) Whether the parent (or consolidated enterprise) is diversified into non-utility operations. (Ex. 39, Ahern Rebuttal, p. 4).

Spire Missouri's Stand-Alone Capital Structure Should Be Adopted

In this case, the Commission should use Spire Missouri's actual capital structure as of the true-up date of September 30, 2017 which is as follows:

Spire Missouri (Formerly Laclede Gas Company)
Capital Structure as of September 30, 2017)

	Percentage Amount	of Capitalization
Long –Term Debt	$990,894,186	45.8%
Common Equity	1,170,951,764	54.2%
Total	$2,161,845,950	100.0%

(Ex. 22, Buck True-Up Direct, p. 3)

The Commission in the past has used the actual capital structure of the public utility, or its ultimate holding company parent when the ultimate parent is traded on the open market. (Tr. 1319-20).

In recent natural gas cases, the Commission has used the public utility's stand-alone capital structure. (See e.g., Ex. 58; *Report and Order*, ***Re: Summit Natural Gas of Missouri. Inc.,*** Case No. GR-2014-0086, pp. 36-42)(October 29, 2014)(Tr. 1283); or an intermediate parent that operates the public utility. (Ex. 59; *Report and Order*, ***Re Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities,*** Case No. GR-2014-0152, pp. 17-18) (issued December 3, 2014).

In these cases, the Company believes that using the Spire Missouri's Inc.'s capital structure is unquestionably the appropriate course of action for a variety of reasons.

COMPARISON OF CAPITAL STRUCTURES

The following table illustrates the various capital structures that will be discussed below:

	Spire	Staff	OPC/MIEC	Staff in GR-2014-0007
Equity	**54.20%**	**45.56%**	**47.20%**	**53.56%**
L.T. Debt	**45.80%**	**47.97%**	**52.80%**	**46.44%**
S.T. Debt	**0.00%**	**6.47%**	**0.00%**	**0.00%**
TOTAL	**100.00%**	**100.00%**	**100.00%**	**100.00%**

The Company presented the testimony of four witnesses, Pauline Ahern, Robert Hevert, Steve Rasche, and Glenn Buck, who each recommended that the actual capital structure ratios of Spire Missouri, Inc. at September 30, 2017 (true-up date) be used to establish an allowed overall rate of return for the Spire Missouri. (Ex. 40, Ahern Surrebuttal, pp. 24-25; Ex. 36, Hevert Surrebuttal, pp. 15-16; Ex. 37, Rasche Surrebuttal, p. 18; Ex. 22, Buck True-up Direct, pp. 1-2) These ratios are shown in the True-up Direct Testimony of Glenn Buck, p. 2 (Ex. 22, Buck True-up Direct, p. 2). The utility-specific capital structure as of the true-up date consisted of 45.80% long-term debt and 54.20% common equity, which is substantially the same as the capital structure previously used by the Staff for ratemaking in the most recent Laclede Gas Company (MGE division) rate case, Case No. GR-2014-0007. (Ex. 60; Tr. 1304-06).

The actual stand-alone Spire Missouri capital structure ratios (as of September 30, 2017) are reasonable to use for ratemaking purposes in this case because:

1) The ratios are based on the actual capital structure that finances the assets and operations of the public utility that is the subject of this rate proceeding (Ex. 37, Rasche

Surrebuttal, p. 18);

2) The ratios are at a reasonable level and are consistent with the capital structure ratios maintained by similarly situated natural gas companies upon whose market data was relied upon in deriving the Company's recommended common equity cost rate. (Ex. 37, Rasche Surrebuttal, p. 18; Ex. 38, Ahern Direct, p. 3; Ex. 40, Ahern Surrebuttal, p. 25);

3) The ratios are consistent with the capital structures used by the Staff in the most recent Laclede rate case involving the MGE division where the Staff used the following capital structure: 53.56% (common equity) and 46.44% (long-term debt)(Tr. 1304)(Ex. 60);

4) Spire Missouri, Inc. has an independently determined capital structure, (Ex. 39, Ahern Direct, pp. 3-4);

5) Spire Missouri issues its own long-term debt that is secured by its own assets (Tr. 1306, 1310), and not the assets of its parent Spire, Inc. or any of Spire's other subsidiaries, Alabama Gas Corporation ("Alagasco" and the subsidiaries of EnergySouth, Inc.), (Ex. 39, Ahern Direct, p. 4)(Tr. 1307);

6) Spire Missouri's long-term debt is used to support the operations of the Missouri public utility itself. (Tr. 1311);

7) Spire Missouri's long-term debt is not secured by the assets of the parent, or Spire Inc.'s other public utilities, Alabama Gas Corporation or the subsidiaries of EnergySouth. (Tr. 1307);

8) Spire Missouri's assets do not guarantee Spire Inc's, Alagasco's and EnergySouth's long-term debt. (Ex. 30, Ahern Direct, p. 4)(Tr. 1307);

9) Spire Missouri's assets do not guarantee the long-term debt or the operations of Spire Marketing or Spire STL Pipeline. (Tr. 1307-08);

10) Spire Missouri's stand-alone capital structure supports its own bond rating, (Ex. 39, Ahern Direct, p. 4);

11) The Missouri Public Service Commission approves the long-term debt of Spire Missouri, (Ex. 39, Ahern Direct, p. 4) (Tr. 1308), but not the long term debt of any other Spire public utilities operating outside the state of Missouri. (Tr. 1308);

12) The capital structure of the parent, Spire Inc., includes the common equity of the public utilities, Alagasco and the subsidiaries that were formerly with EnergySouth. (Tr. 1311);

13) The capital structure of the parent, Spire Inc., supports unregulated activities of Spire Marketing, Spire STL Pipeline and other unregulated operations. (Tr. 1311-12);

14) Spire Missouri does not have access to capital that is being used by Spire Inc.'s other subsidiaries. (Ex. 39, Ahern Rebuttal, p. 7);

15) Spire Missouri's stand-alone capital structure (as of December 31, 2016) aggregates to approximately $1.9 Billion, while Spire Inc.'s capital structure is substantially larger ($3.6 Billion) since it supports the other public utility subsidiaries, interstate pipeline, and unregulated subsidiaries. In fact, Spire Inc.'s capital is approximately $1.7 Billion greater than Spire Missouri's total capital, as of December 31, 2016. (Ex. 39, Ahern Rebuttal, p. 7).

For all these reasons, Spire Missouri and its two operating units (Laclede Gas and Missouri Gas Energy) should be evaluated as stand-alone entities, including with regard to the capital structure. (Ex. 39, Ahern Rebuttal, p. 7). The actual Spire Missouri capital structure as of September 30, 2017, should be used for ratemaking in this case.

Staff's Proposed Capital Structure Should Be Rejected

Staff is recommending a vastly different capital structure for ratemaking purposes, based upon a capital structure of Spire Missouri's parent, Spire Inc., including its short-term debt:

Staff's Capital Structure

Equity	45.56%
L.T. Debt:	47.97%
S.T. Debt	6.47%

Staff's recommended capital structure is not consistent with the capital structures of Staff's own proxy natural gas companies, the Commission's long-held precedent to exclude short-term debt from major public utility's capital structures, or the Staff's previously used capital structure of 53.56% common equity/46.44% long-term debt/0.00% short-term debt in the true-up proceeding of Laclede's last rate case. (Ex. 60). For these reasons, the Staff's proposed capital structure should be rejected.

Staff witness David Murray used five natural gas companies (Atmos Energy, Northwest Natural Gas, Southwest Gas, OneGas, and Spire, Inc.) as his proxy group for his cost of capital analysis. (Ex. 204, Staff Cost of Service Report, Appendix 2, Schedule 8). The five-year average common equity ratios for the natural gas companies in Staff's proxy group are as follows[5]:

Atmos Energy	53.73%
Northwest Natural Gas	53.34%,
Southwest Gas	48.85%,
Spire, Inc.	53.53%

(Ahern Direct, Schedule PMA-D2, page 2 of 2).

None of Staff's proxy companies had five-year average common equity ratios as low as

[5] Since OneGas was included in Staff's proxy group, but not Ms. Ahern's proxy group, the five-year common equity ratio for OneGas was not available in the record.

Staff's proposed 45.56% common equity ratio (or Mr. Gorman's proposed 47.20%) for Spire Missouri.

Similarly, Ms. Ahern's seven proxy natural gas companies had common equity ratios which averaged 55.01%, with a median of 53.39%, for the year 2015. (Ex. 39, Ahern Rebuttal, p. 9 and Schedule PMA-D2). The five-year average common equity ratio for Ms. Ahern's proxy group ranged from 53.46% in 2014 to 57.52% during the period of 2011-2015. (Ex. 38, Ahern Direct, Schedule PMA-D2) Like Staff's proxy group, Ms. Ahern's natural gas proxy group also had five-year average common equity ratios above the common equity ratio proposed by Staff and OPC/MIEC in this case.

Second, Staff is proposing to include short-term debt in Spire Missouri's capital structure. As discussed below, this proposal is not consistent with historical ratemaking practices of the Commission for major public utilities, and should be rejected.

Third, Staff's proposed capital structure in this proceeding differs markedly from the capital structure included in Staff's True-Up schedules in the last Laclede rate case involving the MGE division. In Case No. GR-2014-0007, the Staff utilized a common equity ratio of 53.56% and a long-term debt ratio of 46.44% which is substantially similar to the 54.20% common equity ratio and 48.50% long-term debt ratio proposed by the Company in this proceeding. During cross-examination, Staff witness David Murray confirmed that Spire Missouri's common equity ratio in its actual capital structure (as of September 30, 2017) is only 0.64% higher that the common equity ratio that was used by Staff in Laclede's last rate case. (Tr. 1305-06).

Finally, by using the parent company's capital structure, Mr. Murray's recommended approach permits regulatory policies employed by commissions in other states, and financing practices followed by utilities or entities not regulated by the Commission, to affect the rates customers pay in Missouri. All of these financial effects flow up to and are reflected in the parent company's capital structure that Mr. Murray is recommending. Mr. Murray has yet to explain why exposing Missouri utility customers and the rates they pay to the financing activities of other entities not regulated by the Commission is consistent with the ring-fencing provisions Staff has long advocated, or with the Commission's own duty to make the financing decisions that will affect such rates. (Ex. 20, p. 8, lines 3-12).

For all of these reasons, the Staff's proposed capital structure should be rejected in this case.

<u>OPC/MIEC's Proposed Capital Structure Should Be Rejected</u>

Public Counsel and MIEC jointly sponsored the testimony of Michael Gorman in this proceeding on the issue of cost of capital and capital structure. Like Spire Missouri, Mr. Gorman proposed to utilize the actual stand-alone capital structure of Spire Missouri as of September 30, 2017, with one major and unprecedented adjustment. (Ex. 407, Gorman Rebuttal, p. 2, 5-8; Tr. 1376)

Mr. Gorman proposed to remove $210 million of equity from Spire Missouri's capital structure that he alleges is related to goodwill associated with the acquisition of Missouri Gas Energy by Laclede Gas Company. (Ex. 407, Gorman Rebuttal, pp. 4, 14-16) For the reasons stated herein, this unprecedented adjustment should be rejected.

Like Staff, OPC/MIEC with their proposed "goodwill adjustment" are recommending a capital structure that is inappropriate, unreasonable, and unprecedented. By Mr. Gorman's own admission, his common equity ratio is "little light on common equity" (Tr. 1376) and "I found that my adjustment to the Company's capital structure has a relatively thin amount of common equity." (Tr. 1375). Nevertheless Mr. Gorman proposed the following "light" common equity ratio in his proposed capital structure:

OPC/MIEC's Capital Structure

Equity:	47.20%
L.T. Debt:	52.80%
S.T. Debt:	0.00%

Mr. Gorman offers four arguments in favor of his proposed adjustment. First, he argues goodwill "represents a transaction between Spire or Laclede/MGE's investors, and the investors of the entity which is being acquired." (Ex. 407, Gorman Rebuttal, p. 7) He reasons that as a consequence, goodwill "does not represent capital received from investors and used to invest in utility plant and equipment." (Id.) Second, Mr. Gorman argues because it is not included in rate base, goodwill produces no cash flow and, from the perspective of rating agencies, "has no economic value." (Id.) Third, Mr. Gorman states that because goodwill produces no cash flow, it "can only prudently and reasonably be financed by utility common equity"; he argues it would be "imprudent to finance a goodwill asset with debt. (Id. at 8) Lastly, Mr. Gorman suggests that, because any impairment in goodwill would be written off against common equity, his proposed adjustment is properly focused on the common equity balance.

For the reasons explained below, Mr. Gorman's "goodwill adjustment" should be rejected, and Spire Missouri's actual stand-alone capital structure should be utilized in this proceeding.

First, Mr. Gorman did not suggest the acquisition of MGE by Laclede Gas was financed by only common equity. In reality, the assets owned by MGE, both tangible and intangible, were financed by a mix of debt and equity, including the acquisition premium or good will associated with the purchase. Since it is not possible to trace specific portions of the acquisition financing to specific assets, including goodwill, it is inappropriate to suggest that the goodwill was financed by common equity only. (Ex. 36, Hevert Rebuttal, p. 7). As explained by Company witness Robert Hevert, Mr. Gorman cannot say on the one hand that all assets included in the rate base were financed with his proposed mix of long-term debt and common equity, but on the other hand goodwill was financed with common equity alone. Mr. Gorman's assumption that goodwill alone constitutes an exception to the original financing of the transaction and to the principle of fungibility is unsupported and should be rejected. (Id. at 9).

As a practical matter, an equity investor commits funds based on the expectation, and the requirement, to earn a compensatory return derived from all assets (tangible and intangible) owned by the subject company. Any successful capital offering, whether it is debt or equity, depends on the profitability and cash flow generated by the entire enterprise. That was the case in the MGE transaction, for which capital was raised in excess of the book value of MGE's tangible assets, giving rise to the approximately $210 million in goodwill balance. In large measure, the Company was able to recently raise $170 million in long term debt at attractive rates based on investors' expectations regarding the Company's financial strength, including the regulatory capital structure. (*Id.* at 9-10).

Mr. Gorman's approach not only ignores the benefits accruing to customers from those synergies, it would penalize the investors whose capital enabled those benefits in the first place. Again, Mr. Gorman's proposed "goodwill" adjustment is inappropriately one-sided. Laclede financed the acquisition of MGE with more debt than equity, which means the equity ratio used for rate base actually dropped because of the financing of the assets, including goodwill. The rate base, which includes no goodwill, in combination with the capitalization ratio of the utility create the capitalization utilized for determining revenue requirement for ratemaking purposes. It therefore makes no sense to exclude goodwill or an assumed 100% equity equivalent of the same when the transaction was financed with a mix of both debt and equity, the capitalization after the financing included a lower equity content than before the transaction and the rate base was not increased whatsoever to include the goodwill. Simple math alone shows Mr. Gorman's inappropriate exclusion of $210 million of equity from Spire Missouri's capitalization to be entirely without support. Moreover, it is even more egregious because it penalizes the investors whose capital enabled the cost savings that have significantly benefitted customers.

Mr. Gorman's proposed "goodwill" adjustment results in an unreasonable capital structure which, by Mr. Gorman's own admission, is a "little light" or "thin" on common equity. (Tr. 1375-76). As discussed above, his proposed capital structure is not consistent with other similarly situated natural gas companies used in the proxy groups used by Staff and Company in this case. For these reasons alone, his proposal is inappropriate and should be rejected.

Not only is Mr. Gorman's proposal inconsistent with the actual method by which the MGE acquisition was financed, it ignores the basic financial principle of capital fungibility, is inconsistent with how other assets are treated, and runs counter to the Acquisition Stipulation's stated intent in Case No. GM- 2013-0254 to ensure rates are not affected by the MGE acquisition premium. Moreover, if adopted, Mr. Gorman's proposal would reduce the Company's cash flows, increasing the risk of impairment. Because the Acquisition Stipulation in Case No. GM- 2013-0254 calls for customers to be held harmless from the costs of impairment, Mr. Gorman's proposal presents the risk of a cycle in which investors are subject to increasing risks and decreasing returns, eventually threatening the Company's ability to efficiently raise capital. (Ex. 36, Hevert Surrebuttal, pp. 13-15).

As can be seen from Mr. Gorman's peer group on Schedule MGP-3, the Value Line common equity ratio for the utility peers used by Mr. Gorman was 55.3% and the median was 54.0% including Spire. Without Spire, those ratios are 56.5% and 55.6%, respectively. (Ex. 21, Buck Surrebuttal, pp. 9-10) Clearly, Mr. Gorman's proposed common equity of 47.2% is considerably "light" when compared to Gorman's proxy group of similarly situated natural gas companies.

For these reasons, the Company respectfully requests that the Commission reject Mr. Gorman's proposed "goodwill adjustment" and instead utilize its actual capital structure of Spire Missouri in this proceeding.

ii. Cost of Debt – What cost of long-term debt should be used to determine the rate of return?

The Company's actual cost of debt was updated from 4.159% (Ex. 38, Ahern Direct, Schedule PMA-D1 to 4.123% (Ex 40, Ahern Surrebuttal, pp.)(Ex. 68, Noack True-up Direct, Scheduled F) and it should be utilized in connection with Spire Missouri's actual capital structure. For all of the reasons stated above, the Commission should utilize the Company's actual stand-alone capital structure, including its actual embedded cost of debt. Mr. Murray's assertions that a theoretically lower cost of debt should be utilized are without support and run counter to the actual costs of debt that the Company has incurred to finance its assets – costs which are meaningfully lower than they were at it last rate case.

iii. **Should short-term debt be included in the capital structure? If so, at what cost?**

Short-term debt should not be included in the capital structure used for ratemaking in this case. The Company's short-term borrowings are fully utilized to finance its short-term assets not included in rate base, so such debt should not be in the Company's permanent capital structure. As explained by Company witness Glenn Buck, short-term debt should not be included in the capital structure because the average level of construction work in progress and other short-term assets (including propane, margin calls on multi-year hedging programs and deferred gas costs subject to the PGA carrying costs) exceeds the average level of short-term debt outstanding during the true-up period after taking into consideration the September 15, 2017 funding of $170 million of long-term debt instruments. (Ex. 22, Buck True-up Direct,, p. 2; Tr. 1269-70).

Under similar circumstances, the Commission has had a long-standing practice of not including short-term debt in the capital structures of major public utilities in Missouri. (Tr. 1317-19). For example, Staff witness Murray confirmed that the Commission has not included short-term debt in the capital structure of Summit Natural Gas, Liberty Utilities, Kansas City Power and Light Company, and Ameren Missouri. (Tr. 1317-19) Nor Staff did include short-term debt in Laclede's capital structure in the last Laclede rate case, Case No. GR-2014-0007. (Tr. 1304; Ex. 60) In fact, Mr. Buck testified that he was unaware of the Staff or Public Counsel or any other party including short-term debt costs in past cases for 15-20 years. (Tr. 1270). The Commission should not depart from this long-standing practice in this case.

Staff argues for the first time in its surrebuttal testimony that this case is somehow different because Spire Missouri has requested that gas inventories be included in rate base like the gas inventories are treated for its MGE division and every other gas distribution company. (Ex. 259, Sommerer Surrebuttal, pp. 3-5) This position should be rejected, however, for the following reasons:

First, the Staff's approach is not consistent with the long-standing practices of the Commission which has included gas inventories in rate base, but rarely included short-term debt in the capital structures of major public utilities. (Tr. 1510-11). Although Staff originally stated in its direct and rebuttal testimony, that LAC's storage inventory costs should be included in base rates to ensure such costs were treated in the same manner as they are for all other Missouri gas utilities, its attempt to apply a short-term debt rate to such inventories would ensure just the opposite. Ameren, Empire, Liberty and MGE have no short-term debt included in their capital structure, even though all are gas utilities regulated by the Commission and all have gas inventories included in rate base. (Tr. 1435). As a result, adopting of Staff's approach would effectively providing LAC and MGE with a 1.5% return on these costs while other LDCs are permitted to earn a full return which includes the cost of common equity and long-term debt. That is hardly the kind of regulatory consistency that Staff originally endorsed. Including LAC's storage inventory in rate base merely aligns LAC with MGE and the rest of the Missouri gas utilities. It would also provide the Company with a more consistent and less complicated way to account for these costs since the Company would be able to administer storage inventories in one manner instead of applying two different ratemaking treatments. However, there is no reason to change the Commission's policy to include short-term debt in major public utilities' capital structures.

Second, the amount of short-term debt Staff proposes to include in its capital structure is grossly in excess of the value of LAC's gas inventories. Specifically, LAC's gas inventory is approximately $82 million, but Staff proposes to include $283 million of short-term debt in the capital structure. As a result, Staff's approach would include more than $200 million of short-term debt costs in excess of the levels of gas inventories. (Tr. 1491). If moving LAC's storage units to base rates is the pretext for Staff's attempt to include short-term debt in the Company's capital structure, it is not representative of the underlying asset.

Third, it is ludicrous to suggest that a 1.5% return is sufficient to compensate the Company for the additional risk it will undertake as a result of including these costs in its base rates. As Mr. Sommerer acknowledged, once these costs are included in rate base, the Company, rather than customers, will have to absorb the financial impact of any carry cost increases associated with rising interest rates or gas prices. (Tr. 1484). A frozen 1.5% rate is grossly insufficient to compensation the Company for this additional risk.

Finally, it is not unusual to include short-term assets such as cash working capital, and materials and supplies in rate base. (Tr. 1502). Similar to materials and supplies, gas storage utilizes a 13-month average to determine the rate base value, which takes the seasonality out of the asset value and better reflects the reality of the situation – that storage is an asset utilized, year-in and year-out, as part of the utility's distribution business to meet customer needs for natural gas service in a variety of circumstances. For all of these reasons, the Commission should reject Staff's eleventh-hour attempt to change the Commission's practice of excluding short-term debt from the capital structures of major public utilities.

b. Rate Case Expense

i. What is the appropriate amount of rate case expense to include?

Executive Summary: The Commission should approve all prudently incurred rate case expense, especially in a case where the Company was required to file a rate case in order to continue collecting revenues under the ISRS Statute.

Argument:

Until the past few years, rate case expense was judged by a prudence standard. (Case No. AW-2011-0330; Staff Report on Rate Case Expense ("Staff Report"), August 2013, p. 2) However, in a 2015 decision in Case No. ER-2014-0370, the Commission declined to get involved in the details of prudence, and instead awarded KCPL rate case expense in the same ratio as its rate case recovery bore to its rate case increase request. That decision was upheld by the Western District Court of Appeals in 2016. *Re: Kansas City Power & Light Company*, 509 S.W.3d 757 (W.D. Mo. 2016) In this case, Staff has diverged from the KCPL approach by first assigning the Company certain costs (cost of a cash working capital study; Staff withdrew other disallowances), before dividing the remainder between the Company and the customer.

(Ex. 255, p. 9) For its part OPC followed the KCPL decision that Spire Missouri opposes. (Ex. 417, p. 3)

For a host of reasons, Spire Missouri should be able to recover all of its rate case expense in this case. These reasons include the Company's history of modest rate case expense aided by settlements; the fact that the case was driven by the ISRS Statute and not the Company's desire to raise rates; the fact that much of the amount of rate case expense was driven by factors outside of the Company's control; the fact that Spire Missouri's issues were not designed to increase revenue requirement; the need for a policy that avoids the incentive for the Company to drive up its cost of service in order to cut down on rate case disallowances.

LAC has had a sterling record in controlling rate case costs. In its three previous rate cases, it spent a total of $540,000. In its first rate case as owner of MGE, it spent $168,000. (Ex. 255, p. 5) The Company has spent in four rate cases less than KCPL's expense of $1 million in ER-2014-0370. That's not to say that KCPL is imprudent; but rather that Spire Missouri has been very successful in minimizing rate case expense. (Tr. 1716-17) The results in Staff's 2013 study in AW-2011-0330 show that, except for lowest expense in a single proceeding, Spire Missouri held every rate case expense record for large Missouri utilities, including:

Lowest cost per customer;
Lowest percentage of rate case expense to total rate increase requested;
Lowest percentage of rate case expense to total rate increase approved;

In 2013, Spire also acquired the record for lowest expense in a single proceeding when it incurred $80,180 in its 2013 rate case. (Staff Report, p. 6)

A large contributing factor to Spire Missouri's success in controlling rate case expense has been its ability to negotiate resolutions of its rate cases well before the hearing stage. Company witness Buck testified that of the 12 LAC rate cases he had participated in, only one went to a hearing, and that one had seven issues. In other words, the 30 unresolved issues that existed just prior to the hearing in this case is four times the number of issues that LAC has brought to hearing in the previous 11 cases combined. (Tr. 1728-29) This has unmistakably driven up rate case expense in this case. Many rate cases go to hearing, and they all involve Staff, OPC and other regular rate case participants. Spire Missouri was the only party that came into this case with a clean record of peaceful settlements, and it can be inferred that Spire Missouri was not responsible for the large number of issues, nor the increased rate case expense.

Spire's filing of these rate cases was triggered by OPC's April 2016 earnings complaint, the requirement to file LAC and MGE cases together, and the consumer protection provisions of the ISRS Statute, which limited the Company to three years' recovery of ISRS costs without filing a rate case. In fact, the Company filed on the last day possible, April 11, 2017. Since the filing would not have been made but for these factors (Tr. 478), and since the ISRS filing requirement served solely as a consumer protection, in this instance, consumers should bear the prudent expenses of the rate case. As Staff witness Majors testified, the Commission seeks to assign some of the rate case expense to utilities, because they are coming to the Commission to remedy the fact that their costs are too low. (Tr. 1760) In this case, Spire Missouri came to the Commission only to avoid staying out too long. (Ex. 20, p. 17)

A great deal of the rate case expense in this case was driven by matters outside of our control. First, the case did not settle or even come close to settling because a party or parties other than Spire Missouri declined to enter into non-unanimous settlement agreements. These agreements would have been non-unanimous in large part because of a sudden shift in historical OPC positions. Among Company programs that OPC opposed were the low-income red tag repair program, the low-income energy affordability program, almost the entire energy efficiency portfolio, and credit card fees. (Tr. 1708-09). OPC was also the sole outlier on several other issues, such as AMR amortization life, return on pension asset, and SERP, as discussed below. In addition, the Kansas Property Tax issue would have settled but for rejection by the Industrial Intervenors. In Further, there were some rate case expenses that were unavoidable. For example, the Commission required the Company to provide notice of the hearings and local public hearings in these proceedings, a requirement which added $436,000 of expense. (Tr. 1701) Similarly, because of MPSC rules, the Company was required to perform and file depreciation studies for both LAC and MGE at a cost of $54.114. (Tr. 1722)

Many of the issues brought to hearing in Spire Missouri's rate case were, in whole or part, not Spire Missouri's issues. These issues include, but are not limited to, Surveillance (Staff), School Transportation (MSBA, Staff), Energy Efficiency and Weatherization (DE, NHT and Spire Missouri), Low-income Program (Consumer's Council and Spire Missouri), PGA/ACA/Pipeline (Environmental Defense Fund), Combined Heat and Power (DE), and Hydrostatic Testing (OPC). (Tr. 1708, 1733-34) In addition, the Forest Park issue arose from a 2014 event and was raised by Staff and OPC. (Tr. 1709, 1732)

The new issues that were raised by the Company were not the type of issues designed to goose revenue requirement, as the Commission found in the 2014 KCPL case. Included in these were the Revenue Stabilization Mechanism (RSM), a non-revenue producing, two-way usage adjustment mechanism that primarily protected customers from overpaying revenues to the Company in cold winters and underpaying them in warm winters. The environmental tracker is also a reconciling mechanism intended to permit the company to recover its environmental costs, no more and no less. Performance metrics is yet another two-way mechanism designed to make the Company more directly accountable for customer service. Only the synergy sharing request has a revenue effect, and even that represents a small share of the benefits reaped by Missouri customers as a result of the Company allocating costs out of

Missouri to its Alabama and Mississippi utilities. (Tr. 1709)

Adoption of Staff's proposed adjustment and others like it would produce a disincentive to manage rate case expense in the most cost-effective manner possible. Under Staff's approach, a utility is penalized through a disallowance whenever it uses outside resources to meet the technical demands imposed by a rate case. It is difficult to understand how this makes any sense from an economic or policy standpoint. Like peak-shaving, the use of outside resources can meet some of the temporary demands of preparing and processing a rate case, which may occur only once every three or four years, without the need to add a permanent position that would otherwise be reflected in annual rates. This permits a utility to lower what it would otherwise need in rates on an ongoing basis for full time employees. At the same time, the limited one-time cost of these outside resources are typically amortized and recovered over a multi-year period, further reducing the cost impact on customers. (Ex. 20, p. 20-21)

Finally, if a concern over escalating rate case expense was the motivating factor behind the Commission's decision to consider a sharing of rate case expense, then the Commission should recognize that such an adjustment is not appropriate where those circumstances do not exist, as is the case here. To do otherwise, would suggest that extraordinary efforts by utilities to minimize the very costs that the Commission found excessive elsewhere are of no consequence to the Commission. I do not believe that is the kind of message that the Commission should send if it wants to maintain a sound public policy on this issue. (*Id*., p. 20)

ii. **What is the appropriate normalization period for recovering rate case expense?**

<u>**Executive Summary and Argument**</u>**:**

The Company believes three years is an appropriate period to recover rate case expense. The Commission should also take into account frequency of rate cases in determining whether a utility should bear rate case expense. For example, it has been now 4½ years since LAC last completed a general rate case, in which it incurred $80,180 in rate case expense. Given this record, the Company should certainly have built up credit in the rate case expense department.

One way, however, to assess some form of rate case expense to a utility is to lengthen the rate case expense recovery period. At the hearing, Staff recommended a four-year recovery period. (Tr. 1763). If the Company can maintain a four-year stretch between rate increases, it would not be opposed to such a recovery period.

d. PGA/ACA Tariff Revisions

i. Should LAC have new PGA/ACA tariff provisions pertaining to costs associated with affiliated pipeline transportation agreements?

Executive Summary: No. For literally decades, the prudence of the Company's gas supply decisions have been audited annually by the Staff in ACA cases, including review of changes in the gas supply portfolio, and are already subject to affiliate transaction rules. This significant change in approach is being pursued by a national organization that apparently does not believe that the Missouri Commission is capable of protecting customers from imprudent decisions, and seeks to achieve something the Commission is not permitted to undertake – predetermination of prudency of a project ahead of its in-service date.

<u>Argument</u>: These issues relating to the structure and operation of the Company's PGA/Tariff provisions and its Standards of Conduct for gas supply transactions were raised by the Environmental Defense Fund ("EDF"), an environmental advocacy group that operates out of Washington D.C. and that has never before participated in rate case proceedings of either LAC or MGE. EDF has claimed that its proposed changes to the Company's PGA/ACA tariffs and Standards of Conduct are motivated by its suddenly developed concern for the welfare of the Company's customers and even for the welfare of the Company itself.

In fact, it is readily apparent to anyone who has assessed the nature and potential effect of EDF's proposals, that the primary objective of its recommendations is to stymie the completion of the Spire STL Pipeline project – a proposed interstate pipeline that is currently seeking a certification from the Federal Energy Regulatory Commission ("FERC"). EDF, like this Commission, is currently participating in the FERC proceeding considering Spire STL Pipeline's application for a certificate and it has expressed strong opposition to the project. EDF is within its rights to take such a position in that particular forum, but it is singularly inappropriate for it to misuse this state regulatory proceeding to achieve the same result.

The specific regulatory actions that EDF has requested the Commission to take in furtherance of its objective are both misguided and fundamentally inconsistent with the long-standing regulatory principles and practices that have governed the Commission's treatment of gas supply and transportation costs. First, and foremost, the process long followed by the Commission contemplates that it is the utility, not the Commission, that will decide what gas supply and transportation resources will be used to meet the demands of its customers. The prudence of those decisions, and the actions utility management took to implement them, are then reviewed after the fact as part of the Actual Cost Adjustment ("ACA") process employed by the Commission. This process has been acknowledged and described by Missouri courts for many years. As summarized more than two decades ago by the court in ***Associated Natural Gas Company v. Public Service Commission,*** 954 S.W.2d 520, 523 (Mo.App.W.D. 1997):

> The ACA filing procedure also provides the PSC with an opportunity to review the reasonableness of ANG's cost-recouping charges by evaluating ANG's gas acquisition practices during the relevant time period. If the costs have been appropriately incurred, the PSC allows ANG to pass them on to the customers. In order to determine if the costs can be passed through to customers as reasonable charges, the PSC employs a "prudence" standard,

> which will be more thoroughly described in our discussion of ANG's initial points on appeal.

This reliance on after-the-fact prudence reviews rather than pre-approval of gas procurement decision and actions has been repeatedly recognized and endorsed not only by the Commission, but also by stakeholders in the regulatory process, *See e.g.* ***Office of the Public Counsel, Complainant v. Southern Missouri Gas Company, L.P.,*** Case No. GC-2006-0180, Order Approving Unanimous Stipulation and Agreement (April 11, 2006) (Staff and OPC stating that their review of a utility's natural gas hedging plans should be not be construed as pre-approval of those plans). Indeed, the agreement of the parties in these cases to make the Energy Efficiency Collaborative an advisory group, rather than a group that votes on and endorses specific energy efficiency programs in advance, is a more immediate illustration of the desire among stakeholders to avoid pre-approval of specific utility actions. (Ex. 243, pp. 3-4)

Adopting the changes to the Company's PGA/ACA tariffs being proposed by EDF witness Lander (Ex. 650) would constitute a direct and substantial reversal of these long-standing regulatory policies. As Mr. Lander candidly acknowledged, his recommended changes are designed to have the Commission determine now the specific kind of evaluation that should be used to determine what costs the Company would be allowed to recover if it contract for and takes service from Spire STL Pipeline. (Tr. Vol. 19, p. 2016-2017) The evaluation formula recommended by Mr. Lander is, of course, designed to make service from Spire STL Pipeline economically problematic. But the important consideration is that his proposal requires the Commission to pre-determine right now how exactly that evaluation will be performed, including how various resources will be valued, which resources will be deemed reliability related and which resources will be deemed diversity related, and how costs for those resources will be compared to determine which costs can be recovered and which cannot be recovered.

(Ex. 650, p 5, lines 10-26). In short, Mr. Lander proposes that the Commission effectively decide how these procurement decisions will be made rather than the Company's management and presumably live with the consequences of those decisions.

The Company respectfully submits that the Commission should decline this invitation to take over the management of the Company's gas supply resources. In addition to being fundamentally inconsistent with the review process long followed by the Commission, and the fundamental rights of utility management to make such decisions, Mr. Lander's proposal would put the Commission in the impossible position of making incredibly consequential decisions without the benefit of expert advice, analysis or the kind of detailed information one would expect to see to make such judgments in a prudent manner. Certainly, Mr. Lander's 26 pages of testimony do not provide a sufficient substitute for the kind of analysis that would need to be performed.

Moreover, as Staff witness Anne Crowe testified, the kind of analysis suggested by Mr. Lander, does not take into consideration a number of factors, including capacity turn-back opportunities, Standards of Conduct bidding requirements, and increases in other pipeline rates, that would have to be evaluated in order to determine what impact his formula might have on gas costs. (Ex. 234, p. 8, lines 5-18). In fact, Ms. Crowe pointed out that Mr. Lander's formula might actually result in an increase in gas costs and rates, depending on whether certain pipeline rates were used. (Ex. 234, p. 8, line 18 – p.9, line 2).

Ms. Crowe also pointed that Mr. Lander's proposals to apply the bidding requirements of the Standards of Conduct to the procurement of transportation capacity would not necessarily address whether a particular decision was prudent. Moreover, as Company witness Weitzel testified, the application of such standards to the far different analysis required for procuring pipeline capacity would create obstacles to obtaining such capacity on a reasonable basis and put these critical resources at risk. (Tr. Vol. 19, p. 1880). In the end, the Staff recommended that the Commission should make none of the changes proposed by EDF and its witness. Mr. Lander. For all the reasons discussed above, the Company strongly agrees.

e. CAM

i. Should a working group be created following this rate case to explore ideas for modifying the LAC and MGE CAM?

Executive Summary: The Company was the first utility to have a Cost Allocation Manual ("CAM") approved by the Commission and remains one of the few utilities in the state to have a Commission approved CAM. After its recent acquisitions, Spire undertook an extensive process with an industry renowned firm and highly experienced team to review and implement the necessary updates to its allocation processes for the growth achieved over the past four years. The success of that effort is partially reflected by the fact that there are no proposed disallowances for allocations in this case, nevertheless, the Company would not be opposed to participating in a working group to discuss potential improvements to its CAM**.**

Argument: The Company takes its obligation to properly allocate costs between its regulated utilities and unregulated businesses very seriously. To that end, the Company worked with the Staff and OPC to develop the first CAM ever approved by the Commission for purposes of determining how various costs should be direct charged, assigned or fairly allocated among these businesses. Since it was approved in 2013, the Company has continued to work diligently to ensure that costs are being properly charged and allocated under the CAM following Laclede's acquisition of MGE in 2013 and Spire's acquisition of Alagasco and EnergySouth in 2014 and 2016, respectively.

The nature and scope of the Company's efforts in that regard were outlined in the direct testimony of Company witness Tim Krick, the Company's Managing Director and Controller.

(Ex. 23, pp. 8-15). As Mr. Krick explained, the Company has undertaken a number of steps to make sure its allocations are reasonable, transparent and based on sound cost causation principles. (*Id*.) These steps included:

- Conducting an overall assessment of Spire's shared service functions, activities and organizational structure in coordination with a firm (Strategy&) that has decades of experience developing allocation processes and procedures for companies that have multiple utility and non-utility business units.
- Forming a Shared Services Company in 2015 that could be used be used as transparent accounting vehicle for accurately and fairly identifying, charging and allocating shared services costs.
- Undertaking a comprehensive, multi-stage process for not only designing and refining the allocation process based on the input of Stategy& and the employees who would be affected by it, but also for ensuring that such employees thoroughly understood and were trained on how to administer the process.

(*Id*.) Despite these diligent and, the Company believes, successful efforts to develop a vibrant and effective cost allocation process, the Company makes no claims of perfection. As it has in the past, it is open to considering the thoughts, ideas and recommendations of other interested stakeholders on how the CAM and its procedures for charging and allocating costs could be potentially enhanced, especially in the wake of the Company's acquisitions over the past four years.

The Company strongly believes that this objective can be best achieved through a collaborative effort with Staff, OPC and other interested stakeholders that would be undertaken as part of a working group. Such an approach has a number of significant advantages. First, the very existence of the current CAM, which reflected the joint recommendations of the Company, Staff and OPC, signifies that these parties can, in fact, collaborate in an effective manner on such issues. Second, the Company, Staff and OPC are the parties who have the most experience and historical knowledge not only of the Company and its allocation process, but also with the allocation processes being employed by other utilities regulated by the Commission. Third, these parties are the entities most familiar with the Missouri-specific regulatory requirements that might bear on how a CAM is ideally shaped, whether those requirements come in the form of the Commission's affiliate transactions rules or allocation practices in general. Finally, from an efficiency perspective, such a process would permit existing resources to be used to achieve these results, and not require the expenditure of additional funds. For all of these reasons, the Company believes that forming a working group consisting of interested stakeholders is the ideal way to pursue potential enhancements to the CAM.

ii. Should an independent third-party external audit be conducted of all cost allocations and all affiliate transactions, including those resulting from Spire's acquisitions, to ensure compliance with the Commission's Affiliate Transactions Rule, 4 CSR 240-20.015?

Executive Summary: No. The Company has already used a prestigious accounting and consulting firm with significant industry experience to develop and implement updates to its allocation procedures. Hiring another expensive consultant to perform an audit would be wasteful, and its benefits would not outweigh its costs. Any reviews to be undertaken and proposed enhancements can be addressed in the CAM working group.

Argument: OPC has recommended that an independent, third party consultant should be hired to conduct an external audit of all of the Company's allocations and affiliate transactions. The Company believes that there is no basis for incurring the additional cost of hiring a third party consultant to perform such work. Moreover, the Company suggests that such a conclusion is amply supported by the performance of the third-party consultant hired by OPC to look at the very same issues in these cases.

Ms. Ara Azad, the outside consultant hired by OPC to review the Company's cost allocations and affiliate transactions (who incidentally also recommended that a third party consultant be hired to perform such work in the future) demonstrated some of the major downsides that can occur when the wrong outside resources are used. For example, from the very outset of this proceeding, the Commission's internal Staff recognized that it was not appropriate to allocate the costs of the Company's newBlue management information system to Alagasco or EnergySouth, because those utilities still operated under their own IT systems and would not be converted to the newBlue platform until 2020, at the earliest. In performing her allocation work, however, Ms. Azad somehow missed this critical fact and continued to recommend that more than $36 million of these costs be allocated to Alagasco and EnergySouth. (Ex. 400, p. 44, line 9, to page 46, line 11). In fact, she continued to make that recommendation, even in the face of direct testimony by Staff and rebuttal testimony by the Company that clearly demonstrated that there was no factual basis for her allocation. (See Staff's Cost of Service Report, Ex. 205, p. 120; Rebuttal Testimony of Company witness Ryan Hyman, Ex. 32). During cross-examination it became even clearer that Ms. Azad had absolutely no knowledge of what kind of IT systems were used by the Alagasco and EnergySouth utilities and had apparently been unwilling to be educated on the subject by either the Staff or the Company. (Tr. 2024, l. 21- 2028) It was still not until the next day, however, that OPC finally withdrew her proposed allocation of these costs as an issue in these cases.

This experience, in the Company's view, demonstrates two things of relevance to this issue. First, it is a cautionary tale regarding the value of employing yet another outside resource to audit and make recommendations on the Company's cost allocations and compliance with the affiliate transaction rules. Ms. Azad had an opportunity to do that and the only allocation adjustment she could find to make was one that was completely discredited before the proceeding concluded. Perhaps another outside auditor would do a better job, but the experience in this case certainly lends no support to that proposition.

Second, in what was perhaps an effort to excuse her inability to find any substantive allocation flaws in the Company's process that actually survived litigation and warranted a disallowance, Ms. Azad complained repeatedly about her inability to obtain information from the Company regarding these matters. Suffice it to say that those complaints were thoroughly rebutted by the testimony of Company witnesses Krick and Flaherty (*See* Ex. 24, pp. 1-6; Ex. 47, pp. 21-51). Moreover, the Company believes that the credibility of Ms. Azad's complaints over the timeliness and completeness of the information being received has to be seriously questioned in any event, coming as they do from a witness who studiously and stubbornly ignored critical facts that were being provided, such as which Spire entities were using the newBlue information management system.

It should also be noted that many of Ms. Azad's complaints regarding the information she received on the Company's affiliate transactions and cost allocation activities may have flowed from her own fundamental misunderstanding of the Commission's affiliate transactions rules themselves. During cross examination, for example, Ms. Azad was asked about whether the asymmetrical pricing standards of those rules applied to allocations of costs between regulated utilities like Laclede Gas and Alagasco. (Tr. 1943, lines 5-18). Initially, Ms. Azad said they did apply but after thinking about it for some time was unable to explain how applying those standards to inter-utility allocations would not effectively preclude any sharing of corporate support services among those utilities and the substantial savings that come with it. (Tr. 1944, line 7 to Tr. 1945, line 2). Counsel for OPC later tried to clean up by suggesting that utilities could ask for a waiver of the requirement to apply such pricing standards to avoid a such a result, apparently not recognizing that the Company had already received one when its CAM was approved. In any event, this fundamental misunderstanding of the Commission's rules and how they apply is another reason for the Commission to conclude that a sufficient case has not been made by OPC for ordering the retention of an outside auditor in these cases.

Finally, OPC witness Hyneman attempted to justify OPC's proposal to hire an outside auditor by attaching to his surrebuttal testimony a copy of the September 1, 2016 Staff's Investigation Report in Case No. GM-2016-342 relating to Spire's acquisition of Alagasco and EnergySouth. (Ex. 425, p. 28, line 20 - p. 30, line 7). Mr. Hyneman even included in his testimony excepts from two news articles that summarized the Staff Report as finding the rates for the Company's customers had increased and service had decreased as a result of these acquisitions. (Ex. 425, p. 28, line 20 - p. 30, line 7).

It is truly unfortunate that OPC would seek to perpetuate this fundamentally false and even defamatory characterization of the customer impacts of these acquisitions. As Mr. Hyneman admitted on the stand, since these are the Company's first rate cases since the Alagasco and EnergySouth acquisitions, its base rates could not possibly have increased in 2016 as result of those acquisitions. (Tr. Vol. 14, p. 583-585). Moreover, the undisputed evidence in these cases shows that rates will actually be significantly lower with these acquisitions than they would have been without them. The assertion that customer service had decreased as a result of these acquisitions is also belied by the undisputed evidence presented in these cases which shows instead the many ways in which customer service has improved over the past several years. Needless to say, an Investigation Report, the contents of which have never been subject to cross-examination, cannot and should not be used as a pretext for wasting money on an outside auditor, when it is so clearly discredited by the evidence which has been presented in this proceeding. For all of these reasons, OPC's request to order an outside auditor should be rejected by the Commission.

f. Gas Inventory Carrying Charges

i. Should LAC's natural gas and propane inventory carrying costs be recovered through rate base inclusion, as currently is the case with MGE, or recovered through the PGA/ACA process?

Executive Summary: LAC's gas storage costs should be moved into rate base, an action that would bring LAC in line with MGE and every other gas LDC in Missouri. Moreover, LAC, like every other Missouri gas utility, should, consistent with the Commission's historical practice, be permitted to earn its overall cost of capital on such inventories, rather than have a short-term cost of debt applied to these costs. Both Staff and OPC have previously argued against including gas supply inventory carrying costs in the PGA; however, OPC has since reversed its position, and more recently Staff has determined that if gas inventories are to be included in rate base, they should be tied to inclusion of even a larger amount short-term debt in the capital structure, even if it cannot be shown the company relied upon short-term debt to finance its rate base.

Argument: Currently, MGE recovers the cost of maintaining its gas storage inventories in its base distribution rates. LAC, on the other hand, recovers these gas inventory costs through its PGA/ACA mechanism. (Tr. 1445) Spire Missouri is proposing that LAC take the same approach as MGE, which is more standard in the industry and helps remove another area of inconsistency between the utilities. The Company has accordingly included the necessary adjustments to LAC's PGA/ACA balances and cost of service to reflect the addition of the average storage inventory costs in rate base, consistent with the approach taken for MGE. (Ex.6, pp. 17-18).

Staff witness David Sommerer stated: "The preferred ratemaking treatment for gas inventory carrying costs in these proceedings should be to include them in rate base" (Ex. 227, p. 5), rather than in gas costs, which would be consistent with the other utilities in Missouri, including MGE. (Tr. 1428,). Staff's position aligns with the Company's position on this issue.[6] Staff, LAC and MGE are in agreement that LAC's storage gas inventories should be reflected in rate base. This approach will make LAC's treatment of these inventories consistent with MGE's, and with the other Missouri gas utilities. Staff's position is consistent with its longstanding policy of limiting the types of costs that are included in the PGA adjustment mechanism. (Ex. 18, Weitzel Surrebuttal, p. 2).

Only OPC witness Charles Hyneman opposes including natural gas storage costs in rate base. (Ex. 410, pp. 6-16). For the reasons stated herein, Hyneman's position should be rejected. MGE has historically included its natural gas inventories in rate base. Staff noted that, in addition, "all other Missouri LDCs have used the 'rate base' approach to recover carrying costs associated with gas inventory in their Missouri jurisdictions" (Ex. 203, Staff Cost of Service ("COS") Report, p. 63). MGE, Ameren, Liberty, and Empire all have storage inventory in rate base. Including LAC's storage inventory in rate base merely aligns LAC with MGE and the rest of the Missouri gas utilities. It would also provide the Company with a more consistent and less complicated way to account for these costs since the Company would be able to administer storage inventories in one manner instead of applying two

[6] The Company, however, disagrees with Staff that short-term debt should be included in the capital structure, as suggested by Staff if gas inventory costs are included in rate base. (See Issue III.a.3 above.)

different ratemaking treatments. (Id.)

In doing so, a 13-month average would be utilized to include for rate base purposes, similar to other inventories, like materials and supplies, which helps to create a more stable, long-term value for this asset that is utilized year-in and year-out to meet the reliability needs of its distribution sales customers. As shown in the updated test year data, the average LAC inventory balances was a significant portion of the seasonal peak level, and as shown by the analysis of Company Witness Glenn Buck, these inventories were part of the financings provided by long-term capital. (Ex. 22, p. 1-2)

For these reasons, the Commission should continue its long-standing practice of including gas inventory costs in LAC's rate base.

ii. Should Line of Credit (LOC) fees be removed from LAC's PGA consistent with inventory inclusion in rate base?

Yes. Consistent with moving the recovery of storage inventory carrying costs from the PGA to base rates without applying short-term debt to the capital structure, the Company agrees that recovery of approximately $4.1 million of carrying costs and associated line of credit fees currently included in the PGA mechanism for Gas Inventory Carrying Cost should also be removed.

h. Credit Card Processing Fees

i. Should an amount be included in LAC's base rates to account for fees incurred when customers pay by credit card, in the same manner fees are currently included in MGE's base rates?

Executive Summary: Yes. Consistent with the longstanding practice of other businesses and of MGE, LAC's customer should be able to pay with credit cards without incurring a separate fee. LAC's rates should include the cost of providing this service, and is a policy supported by the National Association of State Utility Consumer Advocates (NASUCA). The amount to be included should be consistent with the increase in the use of credit cards experienced by MGE.

Argument: The record evidence clearly established that MGE's customers do not pay a fee to pay their bill with a credit card, and MGE has been including these fees in rates since 2010. Including an allowance for credit card fees for LAC would align the two operating divisions and is consistent with the approach taken by other businesses for the convenience of their customers. (Ex. 30, p. 4). While providing additional customer service and value, it is also in the Company's interest to accept a credit card payment, as credit card companies are in a much better position to assess creditworthiness and thus to assume the risk of unpaid debt. (*Id*.)[7]

The National Association of State Utility Consumer Advocates ("NASUCA"), by its resolution approved November 13, 2012, urged state public utility commissions to take actions to effectuate such public policy objectives. As reflected in Exhibit 56:

> Be it further resolved that state public utility commissions are urged to exercise their jurisdiction as necessary and appropriate so as to accomplish the public policy objective that consumers be given an ability to make direct payment of utility bills by debit or credit card without unjustified convenience fees and are urged in particular to include as part of their ratemaking activities and as needed a comparative review of the costs associated with processing payments to utilities by debit or credit card and the cost associated with processing payments to utilities by other means, including traditional check, and to provide and as needed such oversight and direction as to the reasonableness of utility payment accepted policies and practices as may be necessary to advance the public policy objective here stated. (Tr. 1037-1038).

Indeed, in addressing the utilization of the "traditional check" payment method,

[7] While Company and Staff witnesses acknowledged that the resulting level of uncollectibles may decrease over time, no party has proposed such an adjustment in this proceeding. (Tr. 1023), ". . . I think looking at the history at MGE, it took some time, but it appears that bad debts were low -- have lowered since we've taken in credit cards. (Company Witness Noack, Tr. 1025). Responding to cross examination as to whether Staff was proposing any adjustments to bad debt in this case to account for credit card fees, Staff Witness Kunst responded, "We don't know the impact of that. . . . No, there's no quantification of that." (Tr. 1036).

Company Witness Noack observed: "Another advantage of credit card fees is that the check doesn't get lost in the mail, thereby reducing unnecessary collection notices." (Ex. 30, p. 4).

Irrespective of NASUCA's pronouncement, OPC erroneously advocates that such a practice is discriminatory and unfair to consumers. But, as Staff Counsel observed during opening statements: "However, nothing in the statutes actually prohibits costs from being socialized which benefit all customers, and this does not constitute discriminatory ratemaking." (Tr. 1015). Indeed, in redirect examination of the staff witness, the following exchange reflects the Commission precedent for approval of the subject proposal. Responding to the question of whether the Commission has approved credit card fees in past cases, Staff Witness Kunst responded: "I know they were stipulated to in the MGE case. They approved that stipulation. And KCPL got them in Case No. ER-2006-0314. They proposed credit card fees, and reviewing that testimony, I don't believe any party objected to KCPL's treatment in that case." (Tr. 1044).

ii. If yes, what is an appropriate amount to include in LAC's base rates for credit card fees?

Regarding the appropriate amount to include in LAC's base rates for credit card fees, Company Witness Noack candidly acknowledged in Surrebuttal testimony that, rather than assuming that each year going forward the number of credit card payments would be on a level equal to MGE's, there would likely be a ramping up of such payments over time. "Upon further reflection, and based on my experience with MGE, it is more likely that the first year there will be an increase, the second year a bigger increase and so forth until roughly the fourth year, when we would expect a level similar to MGE's experience." (Ex. 30, pp. 4-5). Mr. Noack's Surrebuttal Schedule MRN-S1 reflects the averaging of those four year amounts resulting in an adjustment amount that he believes would be a reasonable level to use in the cost of service.

During the evidentiary hearing, Mr. Noack corrected certain entries on that schedule, resulting in a four-year average adjustment of $1,246,619, rather than the $1,057,932 depicted in Exhibit 30 at page 5.

While criticizing Mr. Noack's original methodology for not taking into account the gradual ramp up of the credit/debit card payments over time, Staff Witness Kunst nevertheless advocates that the only the amount Staff would put in rates is based on current usage as of the 12 months ending 9/30/17. (Tr. 1041). This despite acknowledging that for MGE the credit card usage more than tripled in a period of three years. (*Id*.). The Company respectfully submits that Staff's proposed cost level is understated and the Commission should adopt the above-referenced amount calculated by Company expert witness Noack.

i. Trackers

i. Should LAC and MGE be permitted to implement an environmental tracker?

Executive Summary: Yes. Section 386.266.2 RSMo authorizes the Commission to approve adjustment mechanisms that permit electric, gas and water utilities to recover increases and decreases in their prudently incurred costs to comply with any federal, state, or local environmental law, regulation, or rule. The Commission has also previously permitted the Company to defer and recover in subsequent rate cases certain environmental remediation costs associated with the Company's former manufactured gas plant sites. The environmental tracking mechanism being proposed by the Company in this proceeding reflects a sensible blend of these two sources of authority for dealing with environmental compliance costs and should be approved by the Commission.

Argument: As previously noted, Section 386.266.2 specifically authorizes the Commission to approve adjustment mechanisms for a gas, electric and water corporation to "... reflect increases and decreases in its prudently incurred costs, whether capital or expense, to comply with any federal, state, or local environmental law, regulation, or rule." Such mechanisms must be approved in a general rate case proceeding, which is why the Company is requesting Commission authorization for its proposed environmental tracker in this case.

In addition to this grant of legislative authority, the Commission has also previously used its inherent authority to issue accounting authority orders that permitted the Company to defer for future recovery in a rate case certain environment costs relating to the remediation of Company's former manufactured gas plants. (See Ex. 8, Schedule CEL-S3, for the specific language used by the Commission in authorizing such deferrals).

As explained by Company witness Lobser, the environmental tracker being proposed by the Company relies on these two sources of authority to support a tracker mechanism that: (a) is actually a more modest change to the regulatory process than the law allows and (b) is narrowly but reasonably structured to address the specific needs of the Company. (Ex. 8, p. 21, line 3 - p. 22, line 19). Specifically, the Company is not requesting a mechanism that would permit it to actually adjust rates between general rate case proceedings. Instead, it only seeks to track and defer such costs for future recovery in a rate case proceeding. (*Id.*) Nor is the Company seeking a broad grant of authority to adjust and recover for all expenses or capital costs associated with its compliance with federal, state and local environmental laws, rules and regulations as Section 386.266 permits. Rather it is only seeking to track and recover those remediation costs associated with the former manufactured gas plants owned or previously owned by MGE and LAC.[8]

Given the fact that the Company estimates it may begin incurring significant remediation costs next year – with the potential for substantially greater costs after that – (Ex.

[8] The Company would, of course, continue to pursue reimbursement for such costs from insurers and potentially responsible third parties and offset any deferred costs by such amounts. (Ex. 8, p. 22, lines 10-12).

8, p. 22, lines 6-10) this is an appropriate time to approve such a request. Simply put, the Company should not be required to wait three or four years until its next rate case to utilize such a mechanism. This is especially true in view of the Company's efforts to structure a relatively narrow mechanism that changes the regulatory process less than the law allows and that is fully consistent with the Commission's previous treatment of this issue. In the end, these are costs mandated by governmental authorities for the purpose of protecting the environment and the public and the Company should have a reasonable opportunity to recover them.

j. Surveillance

i. Should LAC and MGE provide surveillance data to the Commission?

Executive Summary: The Company has reached an agreement with both Staff and OPC on this issue under which it would provide both parties with certain surveillance information on a quarterly basis. The Company has also agreed to provide its general ledger and CC&B subledger in a secure format on an annual basis within 45-60 days after the end of its fiscal year. (Tr. Vol 18, pp. 1551-52, 1569) Accordingly, the only remaining dispute on this issue centers on the request of large volume customer representatives to also obtain the quarterly surveillance information. As discussed below, the Company believes this request should be rejected since such parties, unlike the Staff and OPC, are not empowered by law to perform any regulatory function relating to the Company, and are not subject to the same statutory prohibitions on the disclosure of the kind of sensitive, non-public information that would be included in such reports and lack transparency as to which, if any, specific customers of the Company they actually represent.

Argument: The Company has agreed to provide the documents to the governmental entities that are statutorily charged with participating in the regulatory process. However, this is non-public data and the Company should not be required to provide it to any party who might intervene in our cases. Spire Missouri should not be required to provide financial surveillance reports to an organization that purportedly represents one of its customer groups, the industrial customers. Moreover, both Staff and OPC have legal requirements regarding confidential information. Not only do the industrial customers not have such requirements, but because MIEC and MECG are corporations and not associations, they no longer disclose who, if anyone, they are representing. (Tr. Vol. 18, pp. 1555, 1567-68). It is certainly ironic that two entities that demand transparency from the Company lack the transparency to even identify themselves.

It was noted that the MIEC and MECG could obtain information similar to the surveillance reports in a rate case. However, outside of a rate case these entities are not in jeopardy of having their rates increased. Further, in a rate case the information is accompanied by normalization and regulatory adjustments. Outside of a rate case, the surveillance reports are unadjusted. This could lead to confusion as to the true extent of Spire Missouri's earnings, and that confusion could lead to a costly and unnecessary investigation or complaint case.

IV. Rate Design/Class Cost of Service

a. Rate Design

i. Should a Revenue Stabilization Mechanism or other rate adjustment mechanism be implemented for the Residential and SGS classes for MGE and LAC? If so, how should it be designed and should an adjustment cap be applied to such a mechanism?

Executive Summary: Yes, the Company should be authorized to implement a Revenue Stabilization Mechanism ("RSM"). It is a statutorily authorized tool that the Commission can use to offset the effects of weather and conservation. The RSM reduces the exposure of both the Company and the customer to the vagaries of weather. The RSM mitigates the bill impacts of weather, for both the customer and the Company, it permits the Company to be open to simpler rate designs that are less dependent on a high fixed customer charge. In other words, it permits the Company to be open to different rate designs that would otherwise present heightened exposure to weather. It also allows the Company to be agnostic, and even helpful in promoting energy efficiency and other conservation measures. The mechanism should be designed to recover an amount of revenue per customer for the residential and small general service classes using the revenue requirements approved in this case.

The Company has also expressed a willingness in this proceeding to adopt a number of the modifications to the RSM that have been proposed by other parties, including a cap on upward adjustments (with no cap on downward adjustments) and additional communication efforts to inform its customers of how the mechanism operates. As an alternative to its proposed RSM, the Company is also open to the Weather Normalization Adjustment Rider, as set forth in the tariff submitted by Staff in the form of Exhibit 281, as long as the critical modifications discussed below are incorporated into the Rider.

In response to the request made by Judge Dippell, the Company submits that the legal standard that applies to determining whether the RSM is lawful is whether or not it complies with the language and intent of the enabling statute (Section 386.266.3 RSMo), and is consistent with sound regulatory policy.

Argument: *(a) The historical context.* The RSM proposed by the Company in these cases represents a lawful, sensible and effective solution to a problem that has challenged the Commission, gas utilities and their customers for over two decades – namely how to address the chronic under and over-recovery of fixed distribution costs due to weather and conservation.

In 2005, the Missouri General Assembly gave the Commission a specific tool to deal with this problem in the form of a statutory provision authorizing it to approve an adjustment mechanism to account for variations in authorized distribution revenues between rate cases due to weather or conservation-related changes in customer usage. Section 386.266 (3) RSMo.

Initially, the Commission chose to address the impact of weather and conservation through rate design. For LAC, this rate design approach took the form of a Weather Mitigation Rate Design (WMRD) under which all of the fixed distribution costs for residential customers are reflected in the customer charges or a relatively low first block of usage. (Ex. 14, p. 4, lines 7-18). An offsetting adjustment is made to the first block of LAC's PGA rates to mitigate the impact on low use customers of the higher first block in distribution rates. (*Id.*). MGE's rate design focused on the adoption of the straight-fixed variable approach, where all fixed distribution cost were recovered through the monthly customer charge. (Ex. 18, Weitzel Surrebuttal, p. 9-10).

While these approaches did much to reduce the impact of weather and conservation on the recovery of fixed distribution costs, they engendered their own set of issues. Specifically, consumer advocates such as OPC, AARP and Consumer's Council have routinely decried the financial impact of such rate design approaches – especially the straight fixed variable approach – on low use customers. Indeed, because of these impacts, OPC mounted legal challenges to the straight-fixed variable rate design. While those challenges were ultimately unsuccessful, OPC was able to negotiate a modest reduction in MGE's customer charge in MGE's last rate case, and re-established a usage charge. OPC is, of course, pressing for significant customer charge reductions in these cases for both MGE and LAC – all of which would leave the Company and its customers even more exposed to the financial impact of weather and conservation.

Notably, a desire for lower customer charges was also mentioned by a number of the Company's customers at the local public hearings held in these cases. (Tr. Vol. 3, 73-74). Such comments reflected a desire to both reduce the fixed monthly burden that customers living on limited incomes have to pay, and to provide a larger savings benefit when a customer reduces usage through energy efficiency or other conservation measures.

(b) *The benefits of adopting the RSM mechanism*. It is within this unique historical and policy context that the Company has proposed that the Commission seize the legislative tools that have been given it and approve the RSM mechanism it has recommended. Such an action would hardly be a leap into the unknown. As the AGA survey provided by Company witness Weitzel shows, by the end of 2016, 36 states had approved or were considering mechanisms that address many of the same issues as the RSM. (Ex. 18, AGA Presentation). Such mechanisms have also been favorably endorsed by other national organizations and energy stakeholders including the National Housing Trust, the Natural Resource Defense Council and the American Council for an Energy Efficient Economy, as well as by Missouri stakeholders such as Renew Missouri and the Division of Energy. (*Id.*) This significant and growing trend simply recognizes the many benefits provided by such mechanisms.

As summarized by Company witness Lyons in this proceeding, the RSM mechanism recommended by the Company in these cases would:

1. Stabilize customer bills by providing credits when bills are higher than normal due to colder weather (and likely higher natural gas prices), and surcharges when bills are lower than normal due to warmer weather (and likely lower natural gas prices);
2. Provide LAC and MGE with a more stable stream of revenues, and prevent over-collection and under-collection of fixed costs as actual sales vary from

test year sales due to weather and/ or conservation through energy efficiency and other measures;

3. Eliminate LAC and MGE's financial disincentive to aggressively promote conservation through energy efficiency initiatives and programs;
4. Reduce utility earnings' dependence on factors beyond its reasonable control – namely weather; and
5. Provide greater flexibility in rate design so that other objectives – such as reducing the impact of high fixed charges on low use customers – can be addressed.

(Ex. 14, pp. 3-4). In short, the RSM provides an opportunity to protect both the Company and customers from the financial impact of weather, while permitting the Company to reduce customer charges as customers have requested and consumer representatives like OPC have long advocated. At the same time, it would also permit the Company to more aggressively pursue energy efficiency programs and other measures that can help all customers to reduce their usage and their bills for utility service.

(c) How the RSM has been designed to comply with the law and mirror other approved adjustment mechanisms. Moreover, the RSM, as proposed by the Company, would achieve these goals in a manner that is fully consistent with its enabling statute and with similar adjustment mechanisms that are currently in effect. As required by 386.266.3, the Company's proposed RSM isolates the revenue variations that will be adjusted for those customer usage changes resulting from the effects of weather and conservation. Revenue variations due to other factors such as customer growth or losses are excluded. Consistent with the statute's requirement to limit any such mechanism to residential and commercial customers, the proposed RSM would also apply only to the residential and small general service classes of

LAC and MGE. In accordance with the statute, the RSM also provides for any adjustment to be reflected on the customer's bill and provides for an annual reconciliation to ensure that the Company does not over or under-recover for these revenue variations.

In addition to including these features to comply with the statute, the Company has also structured its proposed RSM to reflect some of the basic terms of its approved PGA/ACA mechanism under which it has long operated. Most notably, the RSM would: (a) allow the Company to make up to four adjustments per year, provided that they were spaced at least two months apart; (b) debit or credit any under or over-recoveries to a deferred revenue account; and (c) apply a similar carrying cost equal to the prime rate minus two percentage points to the monthly balances in the account. (Ex. 15, Weitzel Direct, pp. 22-23). Finally, like the PGA/ACA mechanism, the proposed RSM has the same period between when an adjustment is filed and when it goes into effect and the same requirement to submit workpapers at the time of the filing. (*Id.*) All of these features were included in the RSM in an effort to make the regulatory review and administration of the mechanism as familiar and convenient as possible for the Commission and regulatory personnel who will be undertaking that task.

A number of parties have made constructive suggestions in this proceeding as to how the RSM mechanism could be improved. For example, Dr. Marke, on behalf of OPC, suggested that if the Commission adopts the RSM, it should apply a 3% cap on the amount of any adjustment made under the mechanism, ensure that the Company makes a special effort to inform its customers regarding the nature and operation of the mechanism, and have any adjustment stated separately on the bill. The Company's proposed mechanism already accommodates the latter suggestion, and consistent with its efforts over the years to work with other stakeholders on these kind of issues, the Company has also expressed a willingness to adopt Dr. Marke's recommendation regarding customer communications as well as a 3% cap (as measured by overall revenues) on the amount of any adjustment that can be made in a single filing. The Company believes, however, that such a cap should only apply to upward adjustments (so that customers would be able to receive the full value of any credit if the weather were extremely cold) and should provide that any amounts in excess of the cap would be deferred for recovery in subsequent adjustments.

(d) Why criticisms of the RSM are inaccurate or overblown and should be rejected. Other criticisms leveled by Staff and OPC at the RSM, however, were either simply inaccurate or highly exaggerated to the point of being irrelevant. For example, Staff witness Stahlman criticized the RSM on the ground that it would not only adjust for weather and conservation, as identified by the Statute, but would also be impacted by additional factors such as fuel switching, rate switching, the addition of new customers with non-average usage, and economic factors, due to the average use-per-customer construct used in the RSM. (Ex. 238, p. 6) In fact, Mr. Stahlman even suggested that adjusting for revenue impacts due to the effect of energy efficiency activities on customer usage might not be permissible under the statute.

It is a well know canon of statutory construction that a statute, like Section 386.266.3 should be construed in a manner that "avoids unreasonable or absurd results." ***State ex rel. Office of the Public Counsel and Missouri Industrial Energy Consumers v. Missouri Public Service Commission***, 331 S.W.3d 677, 687 (Mo.App.W.D 2011). Statutes should also be construed in a manner designed to ". . . subserve rather than subvert the legislative intent" and not in way ". . .so as to work an unreasonable, oppressive, or absurd result." ***Christian Disposal Inc. v. Village of Eolia***, 895 S.W.2d 632, (Mo.App E.D. 1995), citing ***Jenkins v. Missouri Farmers Ass'n, Inc.***, 851 S.W.2d 542, 545, 546 (Mo.App.W.D.1993).

Staff's criticisms of the proposed RSM, and its interpretation of what it allows or prohibits, are directly contrary to these rules of statutory construction. In effect, the Staff has turned a seemingly broad grant of authority to adjust for revenue variations due to "either weather, conservation or both" into a crimped, highly restrictive grant of authority that, without saying so, affirmatively precludes recognition of any revenue variation that may be related to another factor, no matter how small and inconsequential that factor may be. And they are indeed inconsequential and immaterial as demonstrated by Company witness Weitzel in his surrebuttal testimony. (Ex. 14, pp. 5-17). In an even greater breach of proper statutory construction, the Staff ultimately concludes that the only permissible adjustment mechanism is one that adjusts for weather only – a position that entirely negates the statute's words that adjustments can also be made for revenue variations due to "conservation'.

Section 386.266.3 is very clear in its direction. Any gas corporation may apply to the Commission for approval of a mechanism that would adjust for increases or decreases in residential and commercial customer usage due to variations in (i) weather; or (ii) conservation, or (iii) both weather and conservation. There is a clear implication that there is a difference between changes in usage caused by weather versus changes in usage caused by conservation.

There is no question that the statute authorizes a weather adjustment clause, which is straightforward and can be addressed by the WNAR. The statute also authorizes a conservation adjustment clause. The Oxford English dictionary defines conservation as "prevention of wasteful use of a resource." While the definition appears to imply that conservation is a purposeful act, it would be impossible to determine whether any particular reduction in customer usage was purposeful or not. Since a statute should not be interpreted in a way that makes it impossible, the only reasonable meaning is that "conservation" is meant to be a generic term for customers using less of a resource. Viewed that way, the most reasonable interpretation is that the only two ways customer usage can change is by weather or conservation. The fact that the legislature chose to use the term "conservation" as the catch-all, rather than just saying “weather or other reasons” indicates that it meant to address a change in usage per customer and not just in total residential or commercial usage. Conservation means customers using less (or more) gas, not less (or more) customers using gas. Accordingly, Spire Missouri’s proposed RSM isolates changes to use per customer in order to comply with the meaning of conservation.

The Company respectfully suggests that Staff’s interpretation, if adopted, would “subvert” rather than “subserve” the legislative intent underlying Section 386.266.3. It would also produce the unreasonable and absurd result of suggesting that this significant legislative initiative to address revenue variations between rate cases for gas utilities should be construed in a way that prohibits its use to eliminate the financial disincentive for gas utilities to aggressively pursue energy efficiency and other conservation measures for their customers. In other words, the same legislature that authorized the MEEIA concept for electric utilities – which actually requires ratepayers to financially reward such utilities for pursuing energy efficiency programs -- meant to maintain an affirmative financial disincentive for gas utilities when they do so the same thing, notwithstanding its inclusion of the word “conservation” in the statute. Such an interpretation is about as illogical and absurd as it gets.

Some of the criticisms leveled by OPC witness Marke are even more disappointing. This is especially true since adoption of the RSM would permit the Commission to affirmatively address in a favorable and fair way many of the concerns that OPC has repeatedly raised over the years regarding the impact of high-fixed charges on low-use customers. (Ex. 8, p. 19-21) Rather than seize this opportunity, Dr. Marke unfortunately raises a number of specious arguments in support of rejecting the RSM out of hand. Among others, these include his statement that the RSM constitutes “single issue ratemaking” a contention he makes as if the legislative grant of authority to implement such a mechanism in Section 386.266.3 did not completely obviate such an argument. It does.

Dr. Marke also incorrectly claimed in his rebuttal testimony that the RSM would result in "shifting risk to captive ratepayers away from shareholders by ensuring recovery of the Company's profits irrespective of market conditions or inefficient utility behavior." (Ex. 415, p. 8) As discussed in the testimony of Company witnesses Lobser and Weitzel, however, the mechanism only protects the Company from variations in revenue due to weather and conservation. (Ex. 8, p. 18-21, Ex. 18, pp. 5-17) By its very terms, the RSM leaves the Company fully exposed to the impact of other revenue changes, such as a change in market conditions, such as a loss of customers because of a poor economy or other reasons. (*Id*.) The RSM also leaves the Company subject to any adverse changes in the cost of providing utility service, whether they result from market changes, inefficient or imprudent management practices or other factors. (Id.). OPC's contentions to the contrary are simply incorrect on their face and should be rejected by the Commission.

(e) Response to Weather Normalization Adjustment Rider. For all the reasons set forth above, the Company strongly believes that its proposed RSM should be approved by the Commission for the Residential and Small General Service Classes of LAC and MGE. If for any reason, however, the Commission decides not to approve the RSM, the Company would be open to adoption of the Weather Normalization Adjustment Rider ("WNAR") submitted by Staff as Exhibit 281 on the last day of the regular evidentiary hearings in this case. For the WNAR to be an acceptable and workable alternative, however, it would need to be modified in a number of ways as discussed by Company witness Buck in his affidavit that was submitted as Exhibit EIFS 502.

First, like the proposed RSM, the WNAR Tariff should be approved for both LAC's and MGE's Residential and Small General Service Classes. Because the WNAR Tariff adjustments would not vary based on non-weather-related changes in customer usage, Staff's previous objections to applying the RSM to the Small General Service Classes should not be an obstacle to applying the WNAR Tariff to these classes.

Second, the arbitrary $0.01 per therm (or ccf) limit on adjustments under the proposed WNAR Tariff should be eliminated as its practical effect would be to substantially increase rather than mitigate the exposure of both the Company and its customers to the financial impact of weather-related changes in customer usage compared to today. A $.01 limit is so small that it would effectively eviscerate the entire purpose of such a tariff. Elimination of this adjustment limit would also be consistent with the operation of the Company's PGA clause, the statute that authorizes this kind of mechanism, and the vast majority of similar clauses approved in other jurisdictions. If the Commission determines that some limit is appropriate, the Company would recommend that it: (1) be a limit only on ***upward*** adjustments and (2) that it be set at $0.05 per therm or ccf. This would ensure that any monthly increase for the average customer would not exceed $3.50 while providing customers with an opportunity to receive a larger monthly decrease if the weather was exceptionally cold. The WNAR Tariff should also provide that any adjustment amounts falling outside the $0.05 limit would be deferred for recovery from customers in the next WNAR adjustment.

Third, the WNAR Tariff should allow for at least three adjustments per year, including the annual required one. If the WNAR is to provide bill relief to customers in a cold winter, and balances are to be kept at appropriate levels, at least 3 adjustments should be authorized, provided that, like the PGA mechanism, they must be at least 60 days apart.

The Company views these proposed modifications as ones that, at a minimum, would need to be made for the WNAR to result in an enhancement rather than a retreat from the current rate design in effect for MGE and LAC. Accordingly, while the Company continues to urge the

Commission to approve the RSM, it respectfully requests that the Commission adopt the WNAR with these modifications should the Commission decide not to adopt the RSM.

ii. Reflective of the answer to part i, what should the Residential customer charge be for LAC and MGE, and what should the transition rates be set at until October 1, 2018?

If either the RSM or a modified version of Staff's WNAR is approved, the Company recommends that a customer charge of $23.50 be established for LAC for the transitional period between the time new rates become effective in March and October 1, 2018, with the remaining revenues to be recovered volumetrically. (Ex. 18, p. 18). The $23.50 represents the total amount of fixed charges currently be collected by the Company through its base customer charge and ISRS charges. (*Id*.) On October 1, 2018, assuming an RSM or WNAR is adopted, the Company is proposing that the customer charge be reduced to $17 per month with corresponding increases to the volumetric charge so that the overall impact is revenue neutral. Staff evidence has supported a $22 or $26 customer charge.

For MGE, the Company is recommending a customer charge of $25.50 during the transition period (again based on MGE's current customer and ISRS charges, with the remaining revenues to be recovered through a volumetric charge. (Ex. 18, p. 18) Effective October 1, 2018, assuming an RSM or WNAR is adopted, the customer charge would be reduced to $20 consistent with Staff's recommendation, with corresponding, revenue-neutral, adjustments to the volumetric rate.

The reason these transition rates are necessary and should be adopted by the Commission were discussed by Company witness Weitzel. As Mr. Weitzel explained, because the Company experiences very low customer usage during the interim March to October period, it would lose millions of dollars in revenue if it instead reduced these fixed charges and increased volumetric charges in March. (Ex. 18, p. 17) In effect, the Company is trying to balance the seasonality of its business while implementing an improved rate design in a way that does not indiscriminately harm the Company. It is important to note that this same kind of approach was agreed upon by the parties and approved by the Commission in MGE's last rate case proceeding for the same reasons. *See* ***Re: Missouri Gas Energy,*** Case No. GR-2014-0007, Report and Order (April 23, 2014).

If the proposed RSM or WNAR mechanisms, as modified by the Company, were not approved by the Commission, the customer charge for LAC would need to be increased to $26 as proposed by staff and the customer charge for MGE would need to be increased to $25.50, respectively. In addition, the WMRD would need to be continued for LAC and such a rate design would need to be instituted for MGE. The development and structure of an WMRD for MGE is discussed by Company witness Lyons at pages of 5-6 of Exhibit 14.

The Company would, of course, strongly prefer to have the RSM approved or, alternatively, the Weather Mitigation Adjustment Rider suggested by Staff, with the necessary modifications identified by the Company. If neither are approved by the Commission, however, it is imperative that the WMRD be continued for LAC and implemented for MGE. Otherwise, the exposure of the Company and its customers to the financial impacts of weather will be substantially increased – a result that would represent a significant step backwards from the weather mitigation measures the Commission has previously approved and the policy direction enabled by Section 386.266.3. At a minimum, the Commission should prevent such a counter-productive policy reversal from occurring in this case. Moreover, there should be no concern continuing the WMRD for LAC and extending it to MGE. The mechanism has worked successfully for LAC for many years, is the product of multiple agreements by participating parties endorsing its use, and has gained widespread acceptance by LAC's customers. Again though, the Company would strongly prefer that the Commission approve its proposed RSM for the reasons identified above.

iii. Reflective of the answer to part i, should LAC's weather mitigated Residential Rate Design be modified to collect a customer charge and variable charge for all units of gas sold, or should it be continued in its current form?

If the proposed RSM is approved, the Company has proposed to modify LAC's rate design to match that of MGE, which includes a customer charge and a single volumetric charge for all gas consumed. As previously discussed, however, if the RSM is denied, then LAC should be permitted to retain its weather mitigated rate design, and MGE should be allowed to adopt a similar rate design.

V. Pensions, OPEBs and SERP

Attached hereto for the Commission's convenience is a format used for pension accounting in LAC's prior rate case settlement in 2013. If the Commission chooses to use this form, the amounts that the Commission decides for Pension and OPEB expense under part a can be entered into paragraphs 6 and 11.

a. What is the appropriate amount of pension expense to include in base rates?

Executive Summary: Due to the Company's successful effort to control costs as discussed in the Introduction, there is, for the first time in many years, an opportunity to include in rates amounts sufficient to pay for current pension costs, and to begin amortizing the pension regulatory asset that has accumulated over a number of years, all without a severe rate increase. LAC believes that the Company, employees and customers are best served by including $31 million in LAC's rates and $5.5 million (before transfers) in MGE's rates, which are amounts designed to fund 90% of Pension liabilities. USW 11-6 agrees with LAC and MGE. Staff prefers to fund at the 80% ERISA Minimum level, which translates to $29 million for LAC. Staff now recommends $5.5 million for MGE. OPC's suggestion to include in rates pension expense at the lower FAS 87 level is ill-advised, as it will simply increase the already large pension asset.

Argument:

The pension asset is affected by the amount of the contribution the Company makes to its pension plan compared to the amount of pension expense contributed by customers to the Company through inclusion in current rates. If the Company contributes more than the customer, the pension asset increases. If the customer contributes more than the Company, the pension asset decreases. The LAC pension asset has grown over the years to approximately $160 million, and is a source of some concern. (Ex. 285, Acct. Sch. 02, p.1 (includes disputed $28.8 million pre-1996 asset))

Over the past several years, federal legislation has had the effect of increasing the pension insurance premiums that the Company is required to pay to the Pension Benefit Guaranty Corporation ("PBGC"). The premiums are affected by funding levels, that is, higher pension funding by a company lowers risk to the PBGC, which lowers the Company's insurance premium. (Ex. 21, p. 12)

Over the past 15 years, LAC, with Staff's agreement, has funded at 80%, which is the minimum ERISA level necessary to maintain the ability to pay lump sum options. (Tr. 2180) The pension agreement has allowed for exceptions to increase funding if necessary to maintain the 80% level, or to reduce PBGC premiums. (Ex. 21, pp. 12-13; Ex. 231, p. 7, l. 12-16)

For this case, the Company has proposed $31 million in pension expense for LAC and $5.5 million for MGE (before transfers). This expense amount would permit LAC to increase its funding toward the 90% level, and would lessen the chance of increasing the pension asset. The Company's funding requirements will be less volatile and susceptible to the vagaries of frequent changes in governmental policies. (Ex. 19, p. 9, l. 5 – 10, l. 2) It would also help in lowering PBGC premiums. (Ex. 21, p. 12)

Staff has proposed pension expense of $29 million for LAC and $5.5 million for MGE. Staff's position would continue pension expense at the 80% level. While Staff's position would lower revenue requirement by $2 million, it would add $2 million of exposure to increasing the already large asset, and would not decrease PBGC premiums. The extra PBGC premium cost of the $2 million is $68,000. (Ex. 263, p. 7, l. 4-9) Staff hopes that the effect of higher interest rates on the pension will preclude both of these events. (Ex. 231, p. 8, l. 5-12)

OPC's suggestion to set expense at the even lower FAS 87 level is a poor option that will only increase the pension asset and increase PBGC premiums. (Ex. 263, p. 5)

Both the company and Staff agree to include $8.6 million in rates (before transfers) for Other Post-Employment Benefits (OPEBs) funding. (Ex. 19, p. 10; Ex. 231, p. 5)

In effect, this decision comes down to whether the Commission believes customers should pay $2 million more in pension expense today to save $68,000 and reduce pension expense in the future. Given the history of the pension in building an asset, the insurance savings, and the fact that current customers are facing a relatively minor rate increase thanks to Spire's efforts in controlling costs, the Company believes that $2 million in additional pension expense is a worthwhile investment.

b. What is the appropriate amount of the LAC and MGE pension assets?

Executive Summary: MGE and Staff agree that MGE currently has a pension liability of (-$28.4) million. (Ex. 286, Acct. Sch. 02, p.1) LAC and Staff both agree that approximately $131.4 million has accumulated in LAC's pension asset since 1996. (Ex. 285, Acct. Sch. 02, p.1) LAC maintains that between the time the Company adopted FAS 87 in 1987, and LAC's rate case in 1994, its pension asset accumulated $19.8 million. In addition, between the 1994 and 1996 rate cases, LAC accrued a pension asset of $9.0 million under FAS 88. Together these two assets sum to $28.8 million. The Staff disagrees with both of these portions of the pension asset, and it has been a longstanding dispute between the parties that has never been resolved by the Commission or otherwise. This pension asset exists pursuant to GAAP rules, and there is an excellent opportunity in this case to end the dispute and begin the process of amortizing this asset.

<u>Argument</u>:

This issue threatens a potential write-off of nearly $29 million if the Commission declines to recognize this pension asset. The matter was important enough that LAC retained its former controller, James Fallert, as its witness. Mr. Fallert actually participated in the 1990-2002 cases involved here, and so testified from both the record and his personal knowledge. (Ex. 44, p. 1, l. 17-22; Tr. 2120) Staff was represented by Mr. Matthew Young, a Utility Regulatory Auditor. According to his credentials, this is his first case testifying on pensions. (ex. 205, Appx 1, pp. 65-66)

Beginning in October 1987, LAC adopted revised standards by the Financial Accounting Standards Board (FASB) for accounting for pension expense. (Ex. 44, p. 2, 8) The revised standards were referred to as Financial Accounting Standard (FAS) 87 and 88. The adoption of FAS 87 and FAS 88 changed Laclede's methodology for calculating pension expense under GAAP. If LAC made a contribution to its pension plan that differed from the GAAP accounting expense it recorded under FAS 87/88, LAC was required to book a prepaid asset or liability for the amount of the difference.

Between 1987 and 1990, LAC's contribution and FAS 87/88 expense were very similar and caused neither a meaningful asset or liability. (Tr. 2113) In 1990, LAC filed its first rate case (GR-90-120) since changing to FAS 87/88 expense. By 1996, LAC's cash contributions to its pension exceeded FAS 87/88 expense by a total of $28.8 million more than Staff acknowledges. This consisted of $19.8 million under FAS 87 for the period 1990-94, and $9.0 million under FAS 88 for the period 1990-1996. Staff agrees to LAC's the portion of the pension asset LAC accrued under FAS 87 for the period 1994-1996.

The question is how much did the customers pay in rates for pension expense between 1990 and 1996. If rates had been set based on the Company's cash contributions to the pension plans, then customers had effectively paid the Company for its pension costs and no rate base asset should exist. But if customers had been paying the lower FAS 87/88 GAAP expense per LAC's books, then the customers owed LAC the difference between the lower GAAP expense and the cash contributions - $28.8 million.

As noted above, the FAS 87 portion of this asset covers the period from 1990 to 1994. Beginning in 1994, both parties agree that an asset existed. The FAS 88 asset covers the period from 1990 to 1996. (Ex. 44, p.3, l. 13-18; Ex. 45, p. 2, l. 18 – p. 3, l. 2) It should be noted that FAS 87 and FAS 88 are so closely related that using one for rates necessary implies using the other. In fact, today they are combined under a new codification, ASC 715. (Ex. 44, p. 6, l. 15 – p. 7, l. 2; Tr. 2112)

Having never resolved this difference of opinion with the Staff, LAC has been carrying this asset on its books for more than 20 years with the disposition of the pension asset included in "black box" settlements. Once again, because LAC is applying for its first non-ISRS rate increase in 7½ years, and in the moderate amount of $25.5 million, LAC seeks to have this issue resolved. If favorable, LAC could finally begin the process of amortizing this long-held asset in rates. If unfavorable, LAC could be faced with a $28.8 million write-off. (Ex. 44, p. 8, l. 3-7)

As stated above, no appreciable asset or liability existed at the time LAC filed its 1990 rate case (GR-90-120). In that case, there is no question that both LAC and Staff proposed rates to be set using FAS 87. Staff witness Rackers distinctly testified that Staff used FAS 87. (Ex. 45, p. 4, l. 13 to p. 5, l. 3)

At the hearing, Staff introduced its 1990 direct testimony, in which Staff witness Rackers stated that the "cash contribution is approximately equal to the pension cost as calculated under FAS 87. The Staff does not believe that an adjustment for this fund is necessary at this time." (Ex. 276, p. 10; Tr. 2105) Although this testimony applied to only a very small portion of the Company's pension fund, the excerpt supports LAC's point. If 1990 rates were being set on cash contributions (as Staff currently alleges), then there would be no need for the 1990 Staff to compare them to FAS 87 expenses. Instead, the Staff would merely try to normalize those cash contributions. The only reason that Staff would compare the two is because customers' rates were based on FAS 87, so Staff had to determine if a pension asset or liability was being formed by the difference between the Company's cash contributions and the customers' FAS 87 rates. Consistent with the statement above, Staff found that there was no appreciable difference between the FAS 87 expenses customers were paying and the Company's cash contributions, and therefore Staff concluded that no adjustment to the FAS 87-based rates were necessary. (Id.; Tr. 2114-15) This conclusively demonstrates that customers were paying pension expense based on FAS 87 between 1990 and 1992, and that FAS 87 (and 88) regulatory assets accrued for the difference between cash contributions and the FAS 87 expense for that period.

The 1992 case tells a slightly different story, but with the same ending. The parties had both filed for rates on a FAS 87 basis in 1990 because LAC was required to follow GAAP unless otherwise authorized by the Commission. (Tr. 2116-17) If LAC could get permission to set rates based on cash contributions, it could collect more cash for pensions and avoid the growing asset and volatility that accompanied FAS 87. (Tr. 2118, l. 12-18) Between 1990 and 1992, the Commission did authorize KCPL to set rates for pension expense based on its cash contributions. This signaled to the industry that the Commission was open to approving a FAS

71 exception so LAC could both account for expense purposes and collect in rates amounts based on its cash contributions. (Tr. 2118, l. 19-24)

Based on that prospect, both LAC and Staff filed their direct cases on a cash contribution basis in 1992. However, both witnesses acknowledged that they needed a Commission order to implement FAS 71 and officially change from GAAP accounting (FAS 87/88) to a cash contribution basis. (Ex. 45, p. 5; Ex. 277, p. 8; Ex. 44, p. 4; Tr. 2116) The FAS 71 exception was not approved by the Commission, and the case was settled. The Stipulation and Agreement was silent on the issue as was the order approving it. (Id., p. 5, l. 29 – p. 6, l. 3; Tr. 2118, l. 22 – 2119, l. 6) Mr. Fallert, who was an eyewitness to this case, testified that since no Commission authorization was obtained, customer rates must have been based on FAS 87 expense. (Ex. 44, p. 5, l. 10-12; Ex. 45, p. 6, l. 1-3; Tr. 2119, l. 1-6)

To believe otherwise requires the Commission to assume that both its Staff and the Company agreed to include in rates an amount that reflected an unauthorized accounting methodology. In denying all of the regulatory asset, the Staff has also claimed that rates were based on cash contributions in the 1990 case. Since the Commission did not issue an accounting authorization in either the 1990 case or the 1992 case, in order to agree with Staff, the Commission must therefore assume that its Staff and the Company violated accounting rules not once, but twice. The Commission has no basis in fact to support such an assumption. Rather, the Commission should conclude that its Staff and the Company followed accounting rules and based rates on FAS 87/88 throughout the periods following the 1990 and 1992 rate cases. (Ex. 44, p. 4, l. 3-14) The amount of the asset that accrued during this period was $19.8 million, which asset should be recognized and amortized in rates.

LAC next filed a rate case in 1994, GR-94-220. As indicated above, the parties are in agreement that 1994 rates were based on FAS 87, as modified, and approved by the

Commission. (Ex. 44, p. 5, l. 13 - p. 6, l. 3) Therefore, the parties agree to the amount of the FAS 87 asset that has accumulated since the 1994 case.

However, Staff still disputes that a FAS 88 asset began to accumulate in 1994. Rather, Staff claims that the FAS 88 asset did not begin until the 1996 case. This is incorrect for multiple reasons. First, given the relationship between FAS 87 and FAS 88, LAC would not have treated one as being in rates under GAAP, while the other was in rates as an unauthorized cash contribution. (Ex. 44, p. 6, l. 15 - p. 7, l. 2) Second, as opposed to FAS 87, FAS 88 was not discussed in the 1994 case, because the parties were not amending the FAS 88 methodology. FAS 88 was specifically mentioned in the 1996 case because the FAS 88 methodology was amended in that case. (Ex. 44, p. 6, l. 4-12) Third, the Report and Order in LAC's 1996 rate case (GR-96-193) stated that the Commission was granting LAC authorization to *continue* to utilize FAS 87, 88 and 106 for regulatory purposes. Use of the term 'continue' indicates that LAC had already been using FAS 88 in setting customer rates, consistent with LAC's position in this case. (Ex. 44, p.7, l. 3-9) Fourth, in the 1994 case, Staff initially filed its case on a cash contribution basis, but indicated that a change in law (HB 1405) would cause it to change its position to use FAS 87 and FAS 88 for ratemaking. The law passed and the case was later settled, with changes made to FAS 87. No changes were made to FAS 88, so it can be assumed that it continued to be used for ratemaking purposes. (Ex. 45, p. 6, l. 4-10) Fifth, and most important, in Case No. GR-94-220, Staff witness Boczkiewicz discussed how he normalized FAS 88 gains. This discredits Staff's argument that FAS 88 was not being used for ratemaking in the 1994-96 period. (Ex. 45, p.6, l. 11 – p. 7, l. 11).

There can be no doubt that customer rates in the 1994 case were based on FAS 88. The pension asset should reflect the difference between the Company's cash contributions and FAS 88 expenses for the 1994-96 period. That amount is $9.0 million. (Ex. 205, p. 68)

Beginning with the 1996 case forward, the parties agree on the amount of the FAS 88 related pension asset.

To further emphasize the significance of the fact that the Commission needed to, but did not, approve a ratemaking change to cash contributions in the 1990-1996 era, in its 2002 rate case (GR-2002- 356), the Commission expressly approved the Company's change to a cash contribution basis. (Ex. 45, p. 3, l. 17 – p. 4, l. 2; Tr. 2119, l. 19 – 2120, l. 7)

The adoption of FAS 87 and FAS 88 on October 1, 1987 changed LAC's methodology for calculating pension expense under GAAP and initiated the requirement to book a prepaid asset. There is no reason to believe, and nothing in the record which would indicate, that these changes in expense calculations somehow resulted in a change in ratemaking methodology from expense recognition to cash contributions. (Ex. 44, pp. 8-9)

In the end, Staff has insufficient evidence to support an assertion that LAC is not entitled to begin recovering the disputed pre-1996 pension asset of $28.8 million. For Staff to be correct, it must admit that it agreed to rates based on an unauthorized accounting method. LAC's eyewitness has made the most credible arguments that rates were based on FAS 87/88 in and after the Company's 1990 rate case. Under the circumstances, LAC is amenable to a short recovery period, or a recovery period as long as 20 years. LAC requests that the Commission set a recovery period so the Company can obtain a return of the disputed amount and resolve this longstanding issue.

c. How should pension regulatory assets be amortized?

Executive Summary: Consistent with historical practice, that portion of the Company's prepaid pension asset that is not subject to any serious dispute should be included in the Company's rate base at its overall cost of capital and amortized over a period of 8-10 years. For the portion that has been challenged by Staff, the Company is willing, as a matter of compromise, to obtain a return of the disputed amount over a 20-year period.

<u>Argument</u>:

There is very little dispute over this issue between the Company and Staff. The Company originally suggested a 10-year amortization. (Ex. 19, pp. 10-11) Staff witness Young countered with eight years. (Ex. 231, pp. 8-9) The Company responded that it was not opposed to an eight year amortization (Ex. 20, p.9). In summary, the Company would accept an amortization of its pension regulatory assets in the 8-10 year range. For the portion that has been challenged by Staff, as discussed in part b above, the Company is willing, as a matter of compromise, to amortize it over a 20-year period.

d. What is the appropriate amount of SERP expense to include in base rates?

Executive Summary: The appropriate amount of SERP expense to include in rates in this proceeding is $469,000 after transfers to capital. This amount was derived from a three-year average.

<u>Argument</u>:

This is another issue in which the Company and Staff agree but the issue has been presented for decision because OPC disagrees with Staff's approach to these expenses. (Ex. 21, pp. 16-19) OPC witness Hyneman claims that Staff's SERP expense is excessive, unreasonable and inconsistent with its prior Staff positions. (Ex. 21, p. 17; Ex. 410, p. 17) First it should be noted that the prior Staff positions refers to his own testimony when he was with the Staff, in ER-2012-0174. As to Mr. Hyneman's "excessive" argument, the SERP plan is a restoration plan. It restores lost pension benefits to employees who deferred some of their compensation. It is not an enhanced plan like you might find in some other corporations. But for the IRS limits, SERP expense would have been payable from the qualified plan.

Additionally, the IRS does allow the deduction for these costs when they are paid. (Ex. 21, p. 17)

As noted by Staff, there are very few SERP payments in a given year. Staff is absolutely right to normalize the amount over time, and not to just rely on the test year, as OPC suggests. (Ex. 21, pp. 18-19)

e. Should SERP payments be capitalized to plant accounts?

Executive Summary: No, there is no basis for capitalizing SERP payments as proposed by OPC.

<u>Argument</u>:

This is yet another issue argued solely by OPC. The Company's books reflect SERP costs on a FAS 87 basis according to GAAP. Such costs are booked on an accrual basis over the service life of the employee. We capitalize this FAS 87 accrual in accordance with the USOA, as required. When SERP payments are made, they are not capitalized. OPC's claim to the contrary is simply in error. (Ex. 21, p. 18)

f. Should the prepaid pension asset be funded through the weighted cost of capital or long-term debt?

Executive Summary: The prepaid pension asset represents a sum that investors have advanced that have not yet been paid by customers. Like other assets, the amount should be included in rate base at the normal weighted average cost of capital. Investors do not pick and choose what assets they invest in. They simply invest capital in the Company and expect to receive the Company's WACC in return.

Argument:

OPC witness Pitts recommended lowering the return on pension assets to the pre-tax cost of debt, rather than the historically used weighted average cost of capital. This is nothing more than an opportunistic and very transparent way of lowering the asset return in a way that is inconsistent with the Stipulation and Agreements signed by the Company, Staff and OPC over many years. Those stipulations specified that the asset would receive rate base treatment, with the understanding that such treatment would be at the weighted average cost of capital. (Ex. 20, p. 12, Sch. GWB-R2) The witness' claim that pension funding is risk free is belied by the fact that he is putting millions at risk by himself with his reduced return plan.

As cash is fungible, "earmarking" a funding source to specific assets within the same organizational structure is a fiction. Ultimately, all long-term financing (both debt and equity) will be used to fund all long-term assets, pensions or otherwise.

LAC has been advancing funds to pay the pension shortfall for nearly 30 years. Were the Company to now borrow $150 million to refinance this obligation, its balance sheet would become unnecessarily leveraged in comparison to its peers. Market investors, who consider factors such as actual balance sheet leverage when making investment decisions, would note that such debt loading could constrain the Company's funding alternatives when future capital infusions are needed to support new property investments.

OPC's witness is also incorrect in claiming that the Company has funded $60 million in excess of ERISA minimums. Instead, LAC has only paid $8 million over the ERISA minimum over these many years, and that amount was needed in order to avoid benefit restrictions and provided for in accordance with the Stipulation and Agreements on pension issues in prior cases. In every proceeding since we have been on a "funded" basis, the Staff has reviewed actuarial reports and received copies of all contributions made into the trusts. Each contribution has been property vetted. Finally, and most importantly, the reality is that past contributions made have resulted in the current funded status and funding requirements. Had additional contributions not been made in the past, the current funding requirement needed would have been just that much higher.

OPC's recommendation to provide a return on pension assets based on the Company's weighted cost of debt will simply increase the Company's cost of funding when the Company next goes to the market. In order to keep a balanced capital structure, the Company may have to do its next financing through equity, thereby increasing the weighted average cost of capital. In the end OPC's witness' idea is simply sleight of hand, intended to give the impression that customers are getting something for nothing. (Ex. 20, pp. 11-13; Ex. 21, p. 14)

VI. Income Taxes

b. What is the appropriate amount of accumulated deferred income tax to include for LAC and MGE?

Executive Summary: The Company has determined that the updated total for LAC and MGE is $344 million. The Staff concurs with this amount and has reflected it in its EMS run.

VII. Incentive Compensation for Employees

a. What is the appropriate amount of employee incentive compensation to include in base rates?

Executive Summary: That amount would be the amount in Staff's EMS runs plus the $6.84 million disallowed by Staff. We understand this amount was recently lowered from $8.85 million upon Staff's decision to remove its unlawful disallowance of roughly half of the Union personnel's incentives, which had been negotiated at arms-length as part of their contract. Offering employees the opportunity to earn a portion of their compensation through market-based incentives is a common, prudent and wise way to operate a business and attract qualified applicants and has created tangible, significant benefits for customers. The Company has made its operations more efficient, lowering its historical inclining cost profile, as evidenced by the modest rate increases requested in these cases, and improved its service - all successes achieved through the efforts of employees who have been compensated at a market-based rate through base salary and incentives. It is only reasonable for customers who are reaping these benefits to pay the market value compensation of the employees who produced them. This should include all of the hard-working employees of the Company, from the entry level clerks to the executives.

Argument:

The Company offers incentive plans to motivate, reward and align the interests of employees with all stakeholders, including customers. Incentive plans are an important component of compensation and are needed to remain competitive in attracting, motivating and retaining talent, because most publicly-traded companies our size, including our utility peers, offer incentive plans similar to Spire Missouri's plans. These peers are companies that are similar in size, own gas utilities, and are publicly traded. In fact, Spire Missouri witness Mispagel testified that he was not aware of any publicly-traded company that does not offer an incentive plan to at least its leadership level employees. However, all Spire Missouri employees participate in the Annual Incentive Plan (AIP) because the Company believes all employees should be aligned with its goals and then share in successful efforts to control costs and serve customers. (Ex. 48, p. 5, l. 8 to p. 6, l. 3)

The AIP provides an annual cash payout to eligible union and non-union participants based on four components, each component with its own objectives: corporate performance, business unit performance, and individual performance or team unit performance (applicable to union employees). (Ex. 205, p. 101, l. 28-31; p. 103, l. 22-23) The Company has two distinct incentive plans, an AIP for all employees, and an Equity Incentive Plan ("EIP") for upper management. (*Id*.; p. 105, l. 10-14)

At the hearing, Spire Missouri was represented by Mr. Mark Mispagel, who is a Managing Director in the Human Resource (HR) Department, and is responsible for all aspects of employee compensation and benefits programs. Mr. Mispagel has been involved in HR since attending Rockhurst University, where he received a BSBA with an emphasis in HR. He also has an MBA from St. Louis University. Mr. Mispagel has worked in the compensation and benefits field for large St. Louis companies for over 30 years, including 17 years at Anheuser-Busch, where he was a Group Director of HR and was involved in domestic and international compensation and benefits, executive compensation, and talent acquisition. Mr. Mispagel has been certified by the Society of Human Resources as a Senior Professional in Human Resources, and has been a member of the Human Resource Management Association, the Compensation and Benefits Network, and the local chapter of the Society of Human Resource Management (SHRM), where he served as an officer. (Ex. 48, pp. 1-2)

Staff's witness is Matthew Young, a Utility Regulatory Auditor who has worked at the Commission since 2013. Mr. Young has no experience working in employee benefits or any other field in HR, and has no HR certifications or memberships. He has, however, represented Staff in preparing written testimony on incentive compensation in two KCPL rate cases, and one Veolia rate case. (Ex. 205, Appx. 1, pp. 66-67; Tr. 2687-89)

The witness for USW Local 11-6 (the "Union") is its Business Manager, Mark Boyle. Mr. Boyle testified that he was concerned with other parties' positions to disallow any incentive compensation, because the incentive program has benefitted the Union, the Company and its customers. Mr. Boyle noted that prior to the Union's inclusion in the program, Union members provided a fair day's work for a fair day's pay. Adding the Union to the incentive program has secured many benefits for the customers and the public, including accelerated safety work, reduced leak response time, and improved interactions with customers. Mr. Boyle described how leak response time was improved by adopting MGE's practice in Eastern Missouri, another dividend paid by acquisitions. However, Mr. Boyle noted that the Company must meet its goals in order to fund a program that has greatly benefitted customers and the public. He recommended the Commission give serious consideration to these facts in determining the Company's recovery of incentive compensation. (Ex. 900, pp. 2-3; Tr. Vol. 20, 2176, l.8 – 2178, l.2)

Management's non-earnings-based portion of AIP

This portion of the AIP pertained to the individual objectives for performance in the areas of customer service and the like. (Tr. 2687, l. 4-9) Staff removed this portion of the management AIP because Staff witness Young believed that many of LAC's and MGE's objectives were not challenging enough, were not objective and measurable, did not require improvement over past performance, were not related to Missouri regulated operations, and were not in the ratepayer's interest. Mr. Young included examples of each of these shortcomings. (Ex. 263, pp. 27-32)

However, at the hearing, it became apparent that Staff's witness had reviewed only the titles of objectives for every Spire Missouri employee, and despite his prior experience with KCPL, didn't ask to obtain the description or targeted performance levels to assess. He had not seen the employee's end-of-year comments on performance, nor the supervisor's evaluations or rating. Prior to coming to his determination that the managerial objectives were entirely inadequate, he did not seek or review any information on performance reviews other than the employees' department, the titles of each employee's objective, and the weighting of that objective. (Tr. 2704-06) Staff's witness had been provided with 6,500 objective titles of Spire Missouri employees, but pronounced judgment on the program without following up to obtain any of the above information. (Ex. 263, p. 33, l. 1-4; Tr. 2702, l. 16-18; 2705, l. 11-13)

It was equivalent to a critic judging a book by its title. Having evaluated KCPL's incentive compensation program on two occasions, the auditor should have known that to evaluate the program in the manner he wanted, he needed to request more information.

The auditor's complaint that the objectives were not challenging and were nothing more than expected daily duties is flawed. It is natural that the objective would pertain to the employee's duties. The real challenge of an objective lies in the thresholds of achievement, which Staff's auditor did not review. (Ex. 263, p. 28; Tr. 2709) The belief that as a whole these objectives were not challenging and provided no benefit to customers simply flies in the face of all the evidence in this case. Whether related to costs significantly lower than they would have otherwise been, systems that were updated to be more capable and efficient than previous, processes that have been improved and revised with best practices, or the resulting service levels and rates customers have and will benefit from as a result of these activities, managerial objectives were challenging to employees, game changing for the company, and drivers of direct, quantifiable and meaningful benefits to customers.

Without having the detailed description of the objectives or the performance levels, it is not surprising that Staff's witness made a number of additional errors in his detailed evaluation of these objectives. In summary, he included two objectives that were weighted at zero (Tr. 2702; 2715, l. 16-21); he could not answer a number of question about other objectives or about the subject employee's duty; he did not recognize that objectives were measurable because he had not seen the thresholds (Tr. 2716); and he inappropriately criticized one objective, that the employee pass the annual Commission audit in his area of responsibility, as incentivizing the employee to cheat. (Tr. 2730)

Staff witness Young also had to concede the fact demonstrated by Mr. Mispagel that it is ultimately untenable to have an incentive program that requires incentive goals to rise each year compared to the previous year. (Ex. 48, p. 11, l. 20-p. 12; Tr. 2717, l. 9-19); Finally, given the fact that a significant number of LAC and MGE employees are involved in shared services, it is also not surprising some of the objectives, like their job duties, related to entities other than LAC or MGE. As many employees provide services for entities such as Spire Alabama, Gulf and Mississippi, it is only natural that along with portions of their pay, incentives are also allocated, and so some of the objectives would be related to other entities. Spire Missouri agrees that incentive compensation that does not apply to Missouri regulated operations should be, and are being, allocated to the proper business or jurisdiction. (Ex. 48, p. 11, l. 7-12)

The Staff should assess whether its auditor should even be trying to evaluate an incentive compensation program at such a detailed level. These plans are designed and operated by people like Company witness Mispagel, who has extensive experience and expertise in the compensation and benefits field. In its last written opinion on the subject of incentive compensation, a Report and Order in Case No. ER-2008-0318, dated January 27, 2009, the Commission noted that Staff's witness, a Utility Regulatory Auditor with no real expertise in compensation plans, is not qualified to critique a utility's plan at that level. The Commission found it to be akin to the Staff designing a compensation plan, and noted that Staff should not be trying to do that. Rather, the Commission advised, Staff must evaluate these programs at a higher level and not get bogged down in the details. (Ex. 70, pp. 89-90) It is clear from his rebuttal testimony that Mr. Young got bogged down in the details, although they were details that he had failed to obtain. (Ex. 263, pp. 27-32; Tr. 2698)

What the Staff is qualified to do in evaluating an incentive compensation plan is to understand the concepts of the plan and determine whether the plan has been reasonably structured, supervised and executed. In fact, Mr. Young had received enough high-level information to understand that the supervisor works with the employee to establish goals for a plan year and rates the employee at the end of the year. Mr. Young had no objection to the general structure and operation of the plan. (Ex. 205, p. 103, l. 1-7)

In summary, the Commission should reject Staff's attempt to use its regulatory auditor to try and pick apart an incentive compensation plan that has been professionally designed and executed.

b. **What criteria should be applied to determine appropriate levels of employee incentive compensation?**

Executive Summary: A compensation package, including base salary and incentives, should be market based, reasonable and appropriate for the employee's job function.

Argument: Compensation pay is made up of both base (fixed) and incentive (variable) components. The Company uses industry market data from surveys and other publicly available sources to help determine competitive compensation, both on the base and incentive level, based on the participant's grade and role at the Company. The Company's internal value of the role is also factored in when determining targets. Incentive compensation puts a part of the employee's earnings at risk in exchange for the opportunity to earn more than a normal earnings level. With respect to individual target amounts, the Company also uses that industry market data to help determine competitive target amounts based on the participant's level and role at the Company. The Company's internal value of the role is also factored in when determining targets. Targeted levels for the performance metrics in the annual and long-term incentive plans are set at levels that are challenging, yet attainable, and the target level may not be achieved all of the time. (Ex. 48, p. 6)

c. **Earnings Based Incentive Compensation – Should LAC and MGE be permitted to include earnings based and/or equity based employee incentive compensation amounts in base rates?**

Executive Summary: The Commission should include in rates the expenses related to incentives, whether equity or earnings-based, as part of the incentive compensation package so long as the package is market-based to attract and retain employees and balanced in its approach to create meaningful benefits for customers. Spire Missouri's regulated revenues are based on its cost of service. If employees can increase the Company's earnings by controlling those costs, customers will benefit. In fact, customers are already benefitting from incentives through less frequent rate cases, and are benefitting in these rate cases through rates that are lower than they would otherwise be. Likewise, employee efforts that increase revenues by activities such as customer growth, also benefit customers, because more revenues for the Company means less the customer will pay in increased rates. The Commission has previously approved incentive programs with an earnings component when accompanied by service and operational components in a 'balanced scorecard.' (See Ex. 70, *re: Ameren*, Case No. ER-2008-0318, Report and Order dated January 27, 2009)

Argument:

1. Management Earnings-based Portion of AIP

Although Staff's witness was only willing to refer the Commission to incentive compensation decisions up to 2007, the Commission's most recent word on the subject was actually in 2009. (Ex. 263, p. 24, l. 27 to p. 25, l. 7) What Staff didn't want to admit is that in 2009 the Commission included in rates incentive compensation based on earnings, and based on other financial metrics. (Tr. 2690, l. 22 to 2692, l. 14)

The Commission allowed Ameren to recover the costs of its EIP-M, an incentive plan for managers and directors that was 25% based on earnings per share. The Commission also approved other plans in the Ameren incentive programs that had unambiguous metrics for "financial management of the business," albeit not earnings per share, along with service and operational metrics. (Ex. 70, pp. 86-87, 90)

The 2009 Commission allowed Ameren to recover the cost of its management incentive program because the overall program was not funded purely by financial incentives, but by a mix of earnings and performance metrics. Staff witness Young claims that each objective must show a direct customer benefit. (Ex. 263, p. 27, l. 10; p. 31, l. 15–p. 32) However, the Commission stated that "So long as the overall program does not contain incentives that could be harmful to ratepayers…AmerenUE should be able to recover the costs of incentive compensation through rates." (Ex. 70, pp. 90-91) As demonstrated below, Spire Missouri's program, which is composed of both financial and service incentives, is not harmful to customers. As a result of these incentives, customers are seeing the benefits of these programs through both lower costs and better service. This is not theoretical. It is simply an undisputed fact in this case. (Ex 4, pp. 7-12) Like Ameren, Spire Missouri should be allowed to recover the costs of its incentive program through rates.

Spire Missouri is not trying to argue that shareholders do not benefit. But this is not a situation in which the shareholder has to lose for the customer to win. Rather, earnings-based incentives permit both the shareholder and the customer to win. (Tr. 484, 1. 2-7; Ex. 5, p. 8) In the end, the Commission found that Ameren's program benefitted customers and shareholders. (Ex. 70, p. 91) The Commission should make the same finding in this case.

Spire generally agrees with the Commission's policy as clarified in the 2009 Ameren case. The Commission's position is fully consistent with Spire's views regarding balanced scorecards. Spire agrees that financial incentives without performance incentives could lead to reduced costs, but could also lead to reduced service. On the other hand, performance incentives without financial incentives could lead to increased service, but delivered at a high cost. The balanced incentive program contains both performance and financial incentives to discourage employees from sacrificing one in favor of the other. (Ex. 48, p. 10, l. 8-21; Tr. 485, 1. 9-25)

The Staff's denial of the value of financial metrics is belied by its own direct testimony, wherein Staff favorably views service components in Spire Missouri's AIP that Staff considers to have customer-oriented goals, such as average call handle time, call abandonment rate, OSHA recordable incident rate and leak response time. Staff states that it generally supports such metrics, "as successful achievement of these goals can lead to lower costs incurred by the utility, which lead to a lower cost of service." (Ex. 205, p. 103, l. 25-29) However, improving on the four "customer-oriented goals" is more likely lead to higher rates, not lower. That is, the Company is more likely to increase costs in order to reduce call handle time and abandonment rate (e.g., more telephone representatives), reduce incidents (caution takes more time), and reduce leak response time (more service technicians). This assertion is consistent with, and the converse of, Staff's position, and even the Commission's position, that earnings based incentives could cause service to suffer while lowering rates. (Ex. 70, p. 86; Ex. 263, pp. 25-26)

The inescapable conclusion is that a well-designed utility incentive compensation program contains a mix of financial incentives and service/operational incentives. Spire Missouri's program which relies on a mix of roughly 50% each should be encouraged rather than disallowed. (Tr. 2692, l. 13-14)

The Commission's approval of the Ameren incentive plan acknowledges the truism that earnings are simply revenues minus costs, and when the Company reduces costs relative to revenues, earnings increase. If that happens in a test year, rates decrease. If it happens before a test year, the result may be that there is no test year, because the utility would not need to come in for an increase as soon as it otherwise would have. (Ex. 48, p. 9; Tr. 2723, l. 10-16; Tr. Vol. 14, pp. 550- 554; Ex. 201, pp. 6-7; Tr. 2727, l. 23-2728, l. 8.) This is exactly what is happening with Spire; the Company wouldn't be in this rate case but for the ISRS Statute, and the results you are seeing in this case arise in no small part from an incentive program that rewards financial performance, along with service performance. (Tr. 478; Ex. 4, pp. 9-10)

The financial earnings component of Spire's AIP benefits both customers and shareholders. In a rate case, increased earnings are kept briefly by shareholders between rate cases and allow the Company to stay out of a rate case longer, but then go to customers, who keep those savings going forward, both in the form of a lower absolute level of costs, as well as the lower impact of inflation on the now smaller base of costs. The Company's financial component incentivizes the increased earnings that will soon redound to customers. (Ex. 48, p. 9; Tr., Vol. 18, p. 2721, l. 17-23; p. 2722, l. 4-p. 2723, l. 1

It is singularly unfair to take those results for customers while at the same time denying the Company recovery of the very incentives it paid to achieve those results. We cannot disallow recovery of incentive compensation costs based on the claim that financial savings do not have direct or meaningful enough benefit to customers, while at the same time capturing those savings in rates that are meaningfully lower than they would have otherwise have been The 2009 Ameren case demonstrates that the Commission is willing to recognize that. (Ex. 70)

Staff insists that incentive compensation costs should be borne by those who benefit from the incentive program, believing that financial incentives only benefit shareholders. But Staff had to concede that the same net savings that increases earnings also decreases revenue requirement – a very tangible benefit for customers. (Tr. 2728, l. 9-21) Simply stated, shareholder success translates into customer benefit. So having earnings as a component of an incentive plan simply accomplishes what the customer wants in the first place – lower costs – and a balanced approach can achieve both lower costs and higher quality service.

In summary, there can be no doubt that shareholders and customers both benefit when the Company can increase earnings by lowering cost relative to revenues. Financial incentives should therefore be a part of a balanced incentive compensation plan that rewards better service at a lower cost.

2. <u>Earnings-based equity compensation</u>

Spire's equity incentive plan (EIP) is awarded in stock rather than cash, and has a longer-term view. Its incentives encourage retention of key upper management employees, improved earnings and relative shareholder value. (Ex. 205, p. 105) As demonstrated in great detail above, all three of these components benefit customers as well as shareholders.

Executive incentive pay has been the most controversial for the commission to approve. (Ex. 70, pp. 85-86) However, in this particular case, the incentive provided to Spire executives may have been the most important one for customers. For example, over the past several years, executives at Laclede, including the CEO, have received incentive compensation for meeting growth objectives. Growth arose from Laclede's acquisitions of MGE, Alagasco, Mobile Gas and Willmut Gas. Instead of the approximate 630,000 customers Laclede had prior to September 2013, the Company now serves 1.7 million customers in three states. This growth has allowed the Company to increase its earnings by spreading its costs across a broader customer base, thus lowering its cost per customer. These higher earnings result in lower costs for customers, a benefit customers have enjoyed in the form of lower rate increases sought less frequently. Growth has also created scale to develop and invest in more modern, capable and efficient managerial and technology platforms for the business, which have allowed the Company to leverage operational efficiencies and knowledge across its expanded footprint, which also benefits customers. It is singularly unfair for Staff or anyone else for that matter to insist that customers reap the benefits of the savings achieved by Spire Missouri, while at the same time refusing to ask customers to pay for the very compensation that motivated the achievement of those savings. (Ex. 48, pp. 8-9)

d. **Should LAC and MGE be permitted to capitalize earnings based and equity-based employee incentive compensation amounts in base rates?**

Executive Summary: Employee compensation is charged to a mix of capital and expense, in accordance with GAAP and based on the employee's function. All permitted compensation should follow the same capital-expense path, including base wages and salaries, performance based compensation and earnings based compensation. The Commission should not make an adjustment to any of these capitalized amounts, and should certainly not adjust amounts capitalized prior to the effective date of rates resulting from the stipulations and agreements in the previous rate case.

Argument:

Employee compensation is charged to a mix of capital and expense, in accordance with GAAP and based on the employee's function. All permitted compensation should follow the same capital-expense path, including base wages and salaries, performance based compensation and earnings based compensation. The Company should recover both the expensed and capitalized portion of applicable employee incentive compensation. (Ex. 48, p. 22)

Both the Staff and OPC proposed to exclude from the Company's rate base amounts they believe to be the capitalized portion of incentive compensation from metrics they believe do no provide sufficiently direct or meaningful benefit to customers. (Ex. 205, p. 104, l. 14 to 105, l. 9; ex. 403, p. 24-25). Staff proposes to apply its adjustment to rate base additions made by the Company since 2003, which OPC appears to support.

At the outset, to the extent the Commission agrees with the Company that its market-based incentives should be included in rates, there is no reason to exclude the portion of those incentives that are capitalized. In such case, the capitalizations would be clearly proper and customers would have also received the value of the associated deferred taxes.

However, if a portion of the incentives are not approved for expenses going forward, Staff's disallowances are still inappropriate for a number of reasons. First, although utilities usually allocate a portion of incentive compensation to rate base, the Commission has never disallowed such capitalized amounts. (Tr. 2731, l. 15-23) In capitalizing incentive compensation, the Company was entitled to rely upon the Commission's decision in the Ameren case, *supra*, which permitted incentive compensation programs that were not purely earnings-based, but contained a mix of financial and operational incentives. The Company was also following GAAP accounting in capitalizing related portions of compensation, a practice that is both appropriate and helps to lower the revenue requirement of the overall cost relative to simply expensing such costs. Since Spire Missouri's AIP follows that prescription, a substantial write-off against earnings covering a 14-year period would be a harsh result. Second, Staff's proposal "double-dips" the Company because Staff seeks to disallow the entire amount in rate base even though customers have already received the value of deferred taxes on these rate base items. Staff cannot take away the rate base items, but keep the deferred taxes they provided. Finally, Staff's adjustments also represent a re-trading of the terms of the settlement agreements that were reached in prior rate cases. There are undoubtedly other issues that were settled and disposed of in those cases that the Company might also wish to change if given an opportunity. Absent some special circumstance, those issues are closed and adjustments from those prior periods would be retroactive ratemaking. For all of these reasons, the proposed adjustments should be rejected. Staff should not be permitted to reach back into the past to disallow capitalized incentive compensation that it alleges to be in rates. (Ex. 20, pp. 22-23)

Staff witness Young argues that the Staff can go back fourteen years, because the stipulation language in Spire Missouri rate cases does not preclude it. (Ex. 263, pp. 23-24) But the stipulation language quoted by Staff on page 24 only pertains to principles or methods. In other words, if Staff agreed to evaluate weather in one case based on a 10-year normal, it would not be precluded from changing its methodology back to a 30-year normal in another case. The stipulation and agreement states that parties reached an agreement "resolving all of the issues in this case…" (Case No. GR-2013-0171, Stipulation and Agreement dated May 31, 2013, p. 2) Since Mr. Young noted that capitalized incentive compensation was an explicit issue in those cases, then it must have been one of the issues resolved. (Ex. 263, p. 23, l. 15-19; Tr. 2731, l. 24 – 2732, l. 3) As a resolved issue, Staff's raising it again is a violation of that agreement, which should not be countenanced by the Commission.

The Commission has never removed capitalized incentive compensation from rate base. That certainly doesn't mean the Commission is precluded from doing so, but regulatory fairness would dictate that the change should not be made in a way that triggers a write-off of four years of capitalizations, not to mention fourteen years. Retroactive application would be especially painful to the Company because, as indicated by Union witness Boyle, accelerated safety work has not only created jobs, but ratcheted up the Company's capitalization rates (ex. 900, p. 2).

Since it appears that the Commission will be deciding an incentive compensation matter for the first time in nine years, and deciding a capitalization matter for the first time ever, the Company requests that such decision be applied against the backdrop of all the customer benefits developed by such incentive programs, and if any negative finding be determined, that these adjustments are only applied prospectively.

If the Commission does decide to disallow certain rate base amounts, the figures proposed by Staff should be thoroughly reviewed and adjusted, as they do not account for deferred tax credits already received by customers as a result of capitalized costs, nor do they account for the pass-through benefits of the expense portion of the equity incentive plan, which helps to lower the effective tax rate customers pay. Staff witness Young testified that the adjustment for capitalized incentive compensation was programmed into Staff's model, but it does not appear that the model accounts for deferred taxes. (Tr. 2732, l. 19 to 2733, l. 6) The Staff should have already made the deferred tax adjustment in this matter to avoid double-counting; having failed to do so, there is no evidence of what the proposed disallowance should be; there is only evidence of what it should not be.

e. To the extent the Commission declines to include employee incentive compensation in rates, what adjustment should be made to base salaries paid to employees?

Executive Summary: In the absence of an earnings based incentive program in the market, the Company would have to substantially increase its base pay in order to attract employees. Such an increased base salary at a market rate would almost certainly go unchallenged by Staff. However, Spire Missouri prefers to manage through incentives that are designed to also align the interests of employees and customers and enhance performance levels. The Company would agree to incentive compensation in rates equivalent to the 100% target rate, which is, by definition, what current employees would receive if they performed at expected levels.

Argument:

The Company offers a base salary that is below a market rate, and places the remainder of the employee's expected compensation at risk under the AIP. While some compensation is at risk, there is also opportunity for a reward above expected compensation for superior performance. The Company and Staff agree that offering this opportunity attracts stronger performers. (Ex. 48, p. 6, l. 19-20; Tr. 2712, l. 8-10; Tr. 2721, l. 2-9; Ex. 5, p. 7, l. 20-22)

The Company testified that if it had no incentive program at all, it would likely be paying the equivalent of base salary plus 75% of its full target incentive, including both the performance and financial components of its AIP. (Ex. 48, p. 6, l. 12 – p. 7, l. 9) Of course, at a flat rate of base salary plus the equivalent of 75% of target, with no incentive opportunity, Spire Missouri would not, by definition, be attracting the same level of talent as it does with its incentive program. (Ex. 5, p. 7, l. 20-22; Tr. 2721, l. 2-9) Were the Commission to set cost recovery at base +75%, it would not be compensating the Company for the people it has actually employed, and who have delivered the results that were actually delivered.

Staff testified that, if the Commission decided to allow Spire Missouri to recover the individual performance portion of its AIP, the Commission should approve expenses at the 100% of target level, which Staff and the Company agree represent current employee's expected compensation for that component of the program. (Ex. 263, p. 34, l. 3-10; Tr. 2734, l. 23 - 2735, l. 12) It should be emphasized that Staff's position applies to recovery at 100% of the performance incentive only, which represents roughly half of the AIP; as discussed above, Staff believes that the Company should recover nothing for the financial incentives that have resulted in Staff's recommendation of a rate decrease. The Company would agree that recovery of 100% of target is appropriate but, as discussed above, that should apply to the entire AIP, both the individual and the financial performance metrics.

Had Spire chosen to just pay a higher market-rate base salary, this issue would be resolved because the Staff would have recommended, and the Commission would have approved, market-based salaries. We are here because the Company chose to follow best management practices by creating programs that attract and retain quality employees, then aligns and motivates them to go above and beyond their normal job performance.

In the end, incentive compensation is simply part of a nearly universal market compensation package that employees expect to see and that Companies use to motivate performance. (Ex. 48, p. 5) Spire Missouri's AIP has a balanced level of financial and service performance metrics that have created significant value for customers. (Ex. 5, pp. 7-8) We ask that the Commission maintain the policy it clarified in the Ameren case and approve recovery for Spire's reasonable compensation costs, including the costs of its incentive compensation plans.

IX. Uncollectibles

a. What is the appropriate amount of bad debt to include in base rates?

Executive Summary: The Staff historically includes in rates a three-year average of uncollectible expense. For the most recent three years (excluding the year (2016) in which the Company revised its policy for when it writes-off delinquent accounts) LAC and MGE had a combined average of $14 million per year in uncollectible expense ($9.1 million for LAC and $4.9 million for MGE). Accordingly, that would be an appropriate amount to include in base rates under the approach typically used by the Commission Staff. The Company also included a five-year average in its testimony, and opined that the additional data points may provide an even more representative level of uncollectible expense. The five-year average results in an uncollectible expense level of approximately $12.9 million, ($8.3 million for LAC and $4.6 million for MGE).

Argument: The Staff used a three-year average to estimate uncollectible expense in MGE's last two rate cases, Case Nos. GR-2014-0007 and GR-2009-0355. The Company agrees that using a three-year average is a valid method for estimating uncollectible expense. Historically, LAC estimated uncollectible expense by multiplying an estimated percentage loss factor times normalized Company revenues, which is also a relevant method of estimating uncollectible expense. However, LAC chose to estimate uncollectible expense in this case using a three-year average of actual uncollectible expenses rather than the loss factor ratio in order to enhance the prospects of agreement with Staff on this issue.

In fiscal 2016, the Company made a significant change to its write-off policy for both LAC and MGE. This change precludes a comparison of net write-off levels in 2016 to those experienced before 2016. LAC decided to expand its gross write-off period to 360 days, or approximately one year, for both LAC and MGE. The previous write-off period for LAC was 180 days from final billing following disconnection of service. The previous write-off period for MGE was 30-45 days. This means that LAC would consider a debt to be uncollectible if it was not paid within six months after the final bill was issued following disconnection, while MGE would consider it uncollectible after 30-45 days. The policy change results in the past due accounts not going to gross write-off for 360 days after final billing. (Ex. 23, Krick Direct, pp. 3-5).

The Company's experience has been that customers who are disconnected in the spring and summer months frequently make a payment and reconnect during the upcoming winter period. However, a customer whose service has been off for a year has gone through an entire heating season without gas service, and is very unlikely to pay the debt. Accordingly, LAC believes its write-offs will be less volatile and more reflective of bona fide bad debt by filtering out the effects of those customers who bounce back-and-forth between uncollectible and receivable. (Id.)

In this case, Staff determined a normalized level of uncollectible expense by using the twelve months ending June 30, 2017. The Company disagrees with this approach since a twelve-month period is not long enough to fairly represent bad debt write off trends and fairly project future expense. An average over at least three-years normalizes unusual variances that can occur in a shorter period such as twelve-months. As mentioned above, the Staff used a three-year average to estimate uncollectible expense in MGE's last two rate cases, Case Nos. GR-2014-0007 and GR-2009-0355 and it should do so here. (Ex. 24, p. 8)

Given the timing of the significant change in uncollectible policy, the Company believed that a sensible and practical solution was to use the three-year average for the period immediately prior to the change, which amount came to $13 million. The Company had every reason to believe that such a three-year average would provide a representative view of uncollectible expense, and would be similar to an overlapping period. Therefore, the Company originally elected to use an approach that would be easily understood and did not require detailed and complex workpapers to reconcile and normalize the post-change data to be comparable to the historical policy. However, the Company also reviewed a three, four, and five-year average approach. Of these calculations, Mr. Krick determined that a five-year average is statistically the best predictor of future write-offs because it includes the most data points, which reduces the standard deviation in statistical terms. He confirmed this belief at the hearing. (Tr. 976) Likewise, a three-year average is certainly superior to using a single year's worth of data. Since using three years was also consistent with the approach taken by Staff in MGE's two prior rate cases, Mr. Krick chose to use it for his testimony. (Ex. 24, p. 9) The Company believes that either the three year of five year average would provide a reasonable level of uncollectible expense in rates.

XI. Performance Metrics

XI. Performance Metrics

a. Should a proceeding be implemented to evaluate and potentially implement a performance metrics mechanism? If yes, how should this be designed?

Executive Summary: The Company strongly believes that the Commission should establish a separate proceeding to consider the structure, operation and implementation of a mechanism to align the interests of the shareholder with customers and to hold the Company financially accountable for how well it serves its customers.

<u>Argument</u>: If designed appropriately, incentive mechanisms can better align the interests of the Company and its customers, similar to how the competitive marketplace rewards superior performance and punishes below standard results. When the Company is able to produce results that create benefits for the customer, it is appropriately incentivized, and when it produces results that are below standard, it is held accountable. This is similar to how companies structure their employee compensation, by making incentives part of that compensation to elevate execution. Incentive programs can also create a better and more transparent discipline to review and assess performance on a timelier basis, with reviews and determinations made on an annual basis. Reporting would be provided during the year to provide the Commission with a better sense for how the company is performing in these key areas, and the Company will be further incentivized to take action sooner to improve results. (Ex. 6, p. 43) Additionally, results would be deferred in a regulatory account for review at the next rate case, in the context of all relevant factors, before including in rates.

The use of performance-based metrics has been around since the mid-90’s for utilities and is in place in other states, as the Missouri legislative Interim Committee on Utility Regulation and Infrastructure Investment found in 2016. These mechanisms help focus attention on important activities that provide added value for customers and are often oriented toward goals for customer service/satisfaction, safety, reliability or cost management. Once in place, the Company would work to incorporate these and related metrics with the employee incentive plans to further align stakeholders and help ensure achievement of beneficial results for customers.

The Company had hoped to design such a program during this case, but it turned out to be a little too optimistic. Despite providing further information on the structure of the mechanism and possible metrics to consider in DR responses in May, parties felt the inclusion of performance metrics during the pendency of the case would not be feasible. In lieu thereof, the Company proposed that the Commission establish a separate proceeding to consider the potential approval and implementation of a program that would hold the Company financially accountable for providing quality service as measured by performance metrics to be established by the parties. We ask that the Commission open such a proceeding and permit the parties that participated in this case to also participate in that one. The concept would be to determine if the parties could reach a consensus on such performance metrics, but all parties would have the right to propose, support, or oppose the adoption of any or all performance metrics on any grounds other than the grounds that such a mechanism can only be implemented in a general rate case proceeding.

Staff witness Myers testified that Staff would be willing to participate in such a proceeding if the Commission established one. (Tr. 655, l. 4-8) She opined that the Staff's new Customer Experience Department would spearhead the work on behalf of Staff. (Tr. 657, l. 7 – 658)

OPC witness Marke opposed the idea, but if a proceeding was established, he suspected that he would be tapped to participate. (Tr. 664, l. 8-11) Union witness Boyle was agreeable to a the Chairman's inquiry as to whether the Union would be open to suggestions from the Commission on broad parameters for metrics. (Tr. 2177-78)

To better ensure a successful result, to make sure that the parties have clear direction and to ensure that this experiment is relatively modest in nature, thus addressing a concern of

OPC witness Marke (Tr. 661, l. 1-5; 666, l. 4-8), the Company suggests that the Commission give the following direction to the working group for any program:

(1) the total sum of any positive or negative financial adjustments associated with exceeding or falling below such performance metrics not exceed $2 million annually, after tax, across both business units (LAC and MGE);

(2) that each performance metric have a range of acceptable annual performance that is reasonably achievable based on historical experience;

(3) the Company report quarterly on results, toward an annual result;

(4) any positive or negative financial adjustments for each particular metric be equivalent in value and only be made for performance that falls outside the range established for the metric; and

(5) any financial adjustments be credited or debited each year to a regulatory asset or liability, as applicable, subject to an annual review to confirm their accuracy; and the accumulated net value of such financial adjustments be tracked for return to or recovery from customers over a 4-year period in Spire Missouri's next rate case proceeding.

(Ex. 8, pp. 42-44)

XXI. Transition Costs

h. Should LAC's and MGE's cost of service be adjusted to reflect the recognition of merger synergies through the test year?

Executive Summary: Yes. Permitting the Company to retain a modest share of the substantial savings Spire has achieved for Missouri customers as a result of the Alagasco and EnergySouth acquisitions is entirely appropriate. The Company's quantification of such savings has not been disputed by any party. Moreover, the amount of such savings that the

Company proposes to retain until its next rate case has been calculated based on the method that the Commission has traditionally used to allocate acquisition-related synergies between customers and shareholders. Finally, adoption of such proposal will encourage future actions by utilities that produce real and substantial benefits of customers.

Argument: The Company, Staff and OPC have all suggested that the cost of service approved in these cases for LAC and MGE should reflect, to one degree or another, the substantial synergies achieved as a result of Spire's acquisition of Alagasco in 2014 (now Spire Alabama) and the two EnergySouth utilities in 2016 (now Spire Gulf and Spire Mississippi). These synergies, which are primarily derived by spreading the cost of shared corporate support services over the larger customer base made possible by these acquisitions, were created at absolutely no cost to Missouri ratepayers. Spire and Spire alone paid for the significant transaction, transition and premium costs required to buy Alagasco and the EnergySouth utilities and provide this opportunity for cost sharing.

As outlined in the rebuttal testimony of Company witness Lobser, these savings can be easily quantified as they represent the net amount of shared corporate support services allocated out of the Missouri cost of service for MGE and LAC to Spire Alabama, Spire Gulf, and Spire Mississippi. Such savings amounted to approximately $13MM in 2016 and have been increasing in 2017. (Ex. 7, p. 27; Ex. 8, p. 15, lines 7-13); Ex. 8, p. 15, lines 7-13; Confidential Schedule CEL-S2). Notably, no party has challenged the Company's quantification of these savings.

The Staff and OPC have simply taken these synergies in their entirety and used them to reduce the cost of service being proposed for MGE and LAC in these cases. The Company also agrees that customers should receive the lion's share of these savings, but also believes that there is a compelling public policy rationale for permitting the Company to retain a modest share of such savings until its next rate case. The Company is not suggesting that the Commission should take such action for the purpose of encouraging Missouri companies like Spire to grow. Growth simply for growth's sake has never been a strategic objective of either the Company or its parent. Rather the Company is suggesting that the Commission should permit utilities to retain a share of merger or acquisition savings where there is solid evidence, as there is in this case, that such activities have resulted in real, quantifiable net benefits for customers, especially where no party has disputed such benefits have actually been created.

The Company has proposed a number of approaches that could be used by the Commission to effectuate such a result, including an upward adjustment to the Company's return on equity in this case, the recovery of discrete transaction or transition costs incurred to complete the acquisitions or a simple retention of the a specific, albeit modest, percentage of such synergies. (Ex. 7, pp 30, L1-13). Although the Company continues to believe that these approaches have merit, it carefully considered the rebuttal testimony of Staff witness Mark Oligschlaeger on this issue (*see* Ex. 224, p. 16, l. 1-6).   Consistent with the concepts identified by Mr. Oligschlaeger in testimony, the Company has proposed an approach under which its share of these benefits would be quantified in a manner that is fully grounded in the traditional approach utilized by the Commission for allocating synergies between the utility and its customers when a utility merger or acquisition takes place.

As Mr. Oligschlaeger explained, under the approach typically taken in Missouri, there is generally no recovery of the premiums paid or transaction costs incurred to effectuate such transactions. (*Id.*).   At the same time, utilities are permitted to recover some level of transition costs (to the extent sufficient synergies have been created to cover them) and " . . . should be allowed to retain all of their achieved merger savings through the operation of regulatory lag until new general rates are established, at which point rates would incorporate all merger savings into the utility cost of service" (*Id*). In other words, utilities should be allowed to keep synergies between rate cases at which point they are flowed through to customers. (*Id*.)

This approach for allocating merger/acquisition synergies has worked reasonably well in this proceeding for the MGE acquisition. Specifically, as a result of the Stipulation and Agreement in the MGE acquisition case, and the settlements reached in these cases, the Company will be permitted to recover certain transition costs, albeit at a lower 50% level, that were incurred to integrate Laclede and MGE and to create the synergies and other savings that substantially exceed those transition costs in value. (Ex. 8, p. 13, l. 18 to p. 14, l. 7). Because the closing of the MGE acquisition was in rough proximity to the timing of the 2013 and 2014 rate cases for LAC and MGE, respectively, the Company had approximately 4 years to retain the synergies it achieved as a result of integrating the two operation units. To work effectively and fairly for all acquisitions and mergers, however, the framework needs to be adjusted to fairly account for when a particular acquisition occurs.

Under the ISRS statute, as well as the statute that authorized adjustment clauses for fuel costs incurred by electric utilities, environmental compliance costs incurred by electric, water and gas utilities, and customer usage revenue variations for gas utilities, the prescribed maximum period between rate cases is effectively 4 years. Accordingly, when an acquisition occurs during this 4-year rate case cycle, as did the Alagasco and EnergySouth acquisitions, that framework is unnaturally truncated and no longer provides the same fair and effective results for sharing the synergies that are subsequently achieved. In effect, the utility is prevented from fully receiving its fair share of the cost savings it has invested significant time, effort and dollars into achieving before they are reflected in customer rates.

The benefit to the Company is reduced while the benefit to the customer is increased by effectively shortening the time the utility has to retain the synergies it has created. For example, by the time this case is concluded, Laclede and Spire will have had one year less to retain the synergies achieved as a result of the Alagasco acquisition as compared to the MGE acquisition and three years less to benefit from those achieved as a result of the ESI acquisition.

Taking the one year less of cost savings at the 2017 rate for Spire Alabama, plus three years of savings from the EnergySouth companies, results in an estimate of the total savings level that the Company would have otherwise benefited from had they not been truncated by external and unrelated filing requirements. (Ex. 8, p. 15, l. 13-17). Providing the Company the benefit of just 50% of these cost savings amortized over 4 years would result in a retention amount of approximately $3.2 MM, which equates to less than 20% of the net costs allocated out of Missouri. (Ex. 8, p. 15, l. 17-21, Confidential Schedule CEL-S2). This approach would allow the Company to still benefit from the framework Mr. Oligschlaeger described, while also providing Missouri customers with the vast majority of the benefits from the lower cost of service these synergies have created. (Ex. 8, p. 15, l. 21 to p. 16, l. 2).

The Company believes that permitting the Company to retain a modest share of the savings it has achieved for customers at no cost to them is wholly appropriate and certainly in line with prior Commission treatment of such issues. Again, if the Commission wants to encourage future actions that benefit customers, it should, at a minimum, adapt its own long-standing approach for allocating the benefits of merger and acquisition synergies to the unique circumstances of this case by approving the Company's proposal.

XIV. Customer Programs

The Parties have reached an agreement on all issues relating to its various customer programs, other than the amount of funding that should be authorized for its low-income affordability program (Issue XIV b. iv) and whether a certain amount of funding should be set aside for a pilot program aimed at installing combined heating and power projects in Missouri. (Issue XIV d.) Each will be addressed in turn.

b. Low Income Energy Assistance Program

iv. What is the appropriate funding level for each division?

The Company has proposed a funding level of $600,000 for LAC and $500,000 for MGE, but is open to a moderately higher level of funding should the Commission deem that to be appropriate.

d. CHP

i. Should LAC and MGE implement a CHP pilot program as proposed by Division of Energy?

In the Direct Testimony of DE witness Jane Epperson (Ex. 502), DE proposed that the Commission authorize Spire to initiate a Pilot Program to assist institutional or business customers with deploying CHP to serve critical loads. DE also recommended guidelines to support and enable Spire Missouri to work cooperatively to co-deliver a CHP Pilot Program. If and when a CHP Pilot Program that can be co-delivered with an electric utility is developed and presented to the Commission for approval, all interested parties would have an opportunity to intervene. More specifically, Ms. Epperson proposed that the Commission take certain actions to support and enable Spire Missouri to deliver a CHP pilot program:

- Establishing a definition of critical infrastructure that encompasses the range of CHP applications from individual facilities (e.g., hospitals) to communities (e.g., hospital plus water and wastewater treatment facility, shelter, and grocery store).
- Authorizing Spire to investigate and develop a proposed CHP pilot program to serve critical infrastructure, with a total program budget not to exceed $5.1 million and with each specific project proposed to be included in the program filed with the Commission for its

approval within 60 days.

- Allowing Spire to track, and in the future seek recovery of, the costs of participating in the pilot program. Such costs might include offsetting a portion of the cost of a project's feasibility study following a positive initial screening conducted by CHP TAP identifying a customer as a good candidate for CHP, the cost of any contribution to a project's installed cost, and any buy-down on the rate of interest offered for financing of a project.
- Allowing Spire to extend the cost recovery periods to up to 15 years for customer repayments on the customer portion of the cost of natural gas line extensions and other natural gas facilities necessary to develop a CHP system.
- Allowing Spire to offer on-bill financing to assist potential CHP customers in funding the capital improvements needed for CHP installation.
- Spire should use a societal cost test to evaluate the potential benefits of critical infrastructure projects.
- For projects jointly offered with electric utilities offering MEEIA programs, directing that the costs and benefits of CHP be symmetrically valued by developing a transparent and reproducible formula to reasonably allocate and assign the value of energy savings and project costs between natural gas and electric utilities and customers.
- Allowing a potential CHP pilot program customer to participate in otherwise-applicable EDRs or Special Contract service rates. (Ex.502, Epperson Direct, pp. 20-21).

Staff and Public Counsel opposed these recommendations, largely on the grounds that DE's proposal lacked specificity, is relatively expensive, and may violate the promotional practices rule. (Ex. 214, Eubanks Rebuttal, pp. 4-9); Ex. 424, Robinett Surrebuttal, p. 2-5; Ex. 420, Marke Surrebuttal, pp. 17-20).

The Company has and will continue to cooperate with the Division of Energy on pursuing CHP opportunities in Missouri. The Company believes there is value in pursuing CHP programs, as recommended by DE. However, it also has concerns that more work may be needed to fully implement DE's proposal.

CONCLUSION

For all the reasons set forth above, Spire Missouri Inc. respectfully requests that the Commission resolve the issues in these cases in accordance with the positions taken and recommendations made by the Company in this Initial Brief.

Respectfully submitted,

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ATTORNEYS FOR LACLEDE GAS COMPANY
AND MGE

CERTIFICATE OF SERVICE

I certify that a true and correct copy of the foregoing was served electronically, or hand-delivered, or via First Class United States Mail, postage prepaid, on all parties of record herein on this 9th day of January, 2018.

/s/ Marcia Spangler

Pensions and Other Post-Employment Benefits

6. Laclede shall continue to be authorized to record as a regulatory asset/liability, as appropriate, the difference between the pension expense used in setting rates ($15,500,000) and the pension expense as recorded for financial reporting purposes as determined in accordance with GAAP pursuant to Accounting Standards Codification (ASC) 715 (previously FAS 87 and FAS 88, or such standard as the FASB may issue to supersede, amend, or interpret the existing standards), and such difference shall be recovered from or returned to customers in future rates.The difference between the amount of pension expense included in Laclede'srates and the amount funded by Laclede in accordance with ERISA minimums shall be included in the Company's rate base in future rate proceedings.

7. The Company shall continue to be allowed rate recovery for contributions it has made and will make to its pension trust that exceed the ERISA minimum for any of the following reasons:

(a) the minimum required contribution is insufficient to avoid the benefit restrictions specified for at-risk planspursuant to the Pension Protection Act of 2006, thereby causing an inability by Laclede to pay out pension benefits to recipients in its normal and customary manner, including lump sum payments; and

(b) the minimum required contribution is not sufficient to avoid any Pension Benefit Guarantee Corporation ("PBGC") variable premiums.

Additional contributions made pursuant tothis Paragraph will increase Laclede'srate base by increasing the prepaid pension asset and/or reducing the accrued liability, and will receive regulatory treatment as described in Paragraph 6 of this Agreement.Laclede Gas shall inform the

Staff and Public Counsel of contributionsof additional amounts to its pension trust funds pursuant to this Paragraph in a timely manner.

8. The provisions of ASC 715 (previously FAS 158) require certain adjustments to the prepaid pension asset/Other Post-Employment Benefits ("OPEB") asset and/or accrued liability with a corresponding adjustment to equity (i.e., decreases/increases to Other Comprehensive Income). The Company will continue to be allowed to maintain a regulatory asset/liability to offset any adjustments that would otherwise be recorded to equity caused by applying the provisions of ASC 715 or any other FASB statement or procedure that requires accounting adjustments to equity due to the funded status or other attributes of the pension or OPEB plans. The Parties acknowledge that the adjustments described in this paragraph will not increase or decrease rate base.

9. The Parties further agree that Laclede Gas shall continue to be authorized to revert to the accounting policy it originally implemented upon adoption of FAS 87, for financial reporting purposes only, effective October 1, 2002, including without limitation:

(a) Market-Related Value implemented prospectively over a four-year period;

(b) Amortization of unrecognized gains or losses only to the extent that they fall outside of a 10% corridor as described in FAS 87 and FAS 106; and

(c) Amortization of unrecognized gains or losses falling outside of the 10% corridor over the average remaining service life of participants.

10. The Parties further agree that gains and losses for all pension lump-sum settlements shall continue to be calculated only to the minimum extent permitted by ASC 715 (previously FAS 88).

11. The Parties agree that the rates resulting from this case also make provision for the recovery of OPEBs costs on an ASC 715 (previously FAS 106) basis. The Parties further agree that the Company shall continue to be authorized to apply its accounting policy for OPEBs consistent with ASC 715 (previously FAS 87) for pensions, for financial reporting purposes, as was initially effective October 1, 2002. The Parties agree that the rates established in this case for ASC (previously FAS 106) expenses include an allowance of $9,455,000 (amount stated prior to application of transfer rate). The Company will fund the trusts based on ASC 715 (previously FAS 106) as calculated for financial reporting purposes. The difference between the amount of OPEB expense included in Laclede's rates and the amount funded by Laclede shall be recorded in a regulatory asset/liability, as appropriate, and such difference shall be recovered from or returned to customers in future rates and included in the Company's rate base in future rate proceedings. Laclede may consider the funded status of the OPEB trusts in determining the allocation of contributions to the trusts.

12. In the event that ASC 715 (previously FAS 106) OPEB expense becomes negative, the Company shall set up a regulatory liability to offset the negative expense. In future years, when such expense becomes positive again, the amount in rates will remain zero until the prepaid asset, if any, which was created by the negative expense, is reduced to zero. The regulatory liability will be reduced by the same rate as the prepaid asset. This regulatory liability is a non-cash item and should be excluded from rate base in future years.