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MISSOURI PUBLIC SERVICE COMMISSION

COMMISSION STAFF DIVISION

AUDITING DEPARTMENT

REBUTTAL TESTIMONY

OF

KEITH MAJORS

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Date 2-28-17 Reporter XF
File No. ER-2016-0285

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2016-0285

Jefferson City, Missouri
December 2016

** Denotes Highly Confidential Information **

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REBUTTAL TESTIMONY

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KEITH MAJORS

KCP&L GREATER MISSOURI OPERATIONS COMPANY

CASE NO. ER-2016-0285

Q. Please state your name and business address.

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

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

A. I am a Utility Regulatory Auditor with the Missouri Public Service Commission ("Commission").

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

A. Yes. I provided testimony in Staff's Revenue Requirement Cost of Service Report ("COS Report"), filed November 30, 2016, in this case. I provided testimony concerning income tax expense, accumulated deferred income taxes, pensions, other post-employment benefits, and other matters.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the direct testimony of Kansas City Power & Light Company ("KCPL" or "Company") witnesses Scott H. Heidtbrink, Darrin R. Ives, and Tim M. Rush concerning the concept of "regulatory lag" and KCPL's alleged inability to earn its authorized rate of return. On this basis, KCPL has requested the authority to implement several new trackers, or alternatively forecasted treatment of certain expenses, all of which the

Commission has summarily rejected in past KCPL and its affiliated company, KCP&L Greater Missouri Operations Company ("GMO"), rate cases.

I will also respond to KCPL witness Ronald A. Klote's direct testimony concerning Adjustment CS-108 – "Transource CWIP/FERC Incentives".

Q. Do other Staff witnesses provide rebuttal testimony concerning regulatory lag and trackers?

A. Yes. Staff witness Mark L. Oligschlaeger is providing an overview on the subject of trackers and forecasted expense treatment requested by KCPL in his rebuttal testimony. Staff witness Karen Lyons addresses the transmission expense tracker and property tax tracker as well in her rebuttal testimony.

EXECUTIVE SUMMARY

Q. Please summarize your rebuttal testimony.

A. I will respond to KCPL witness Heidtbrink's and Rush's direct testimony concerning regulatory lag and KCPL's ability to earn its authorized rate of return, and the impacts, both positive and negative, of regulatory lag. My testimony will address the negative, unbalanced view of regulatory lag that KCPL presents in its direct testimony and discuss how regulatory lag is an important mechanism in ensuring efficiency and fair rates.

I discuss KCPL and GMO's surveillance reports, earned return on equity, and the financial markets' view of the Missouri regulatory environment.

I will also respond to KCPL witness Klote's direct testimony concerning Adjustment CS-108 – "Transource CWIP/FERC Incentives." KCPL performed a calculation of the differential between Federal Energy Regulatory Commission (FERC) and Missouri Commission concerning the transmission projects transferred to Transource Missouri

("Transource") in File No. EO-2012-0367. Staff recommends an adjustment to the calculations to conform to the *Report and Order* in File No. EA-2013-0098. The Commission consolidated File No. EO-2012-0367 into EA-2013-0098.

<u>EARNINGS FROM SURVEILLANCE REPORTS</u>

Q. What is a surveillance report, and what information does it contain?

A. Surveillance reports are quarterly reports on the actual earnings results required to be filed per the fuel adjustment clause ("FAC") rules. KCPL also submits annual surveillance reports pursuant to the November 23, 1987 *Order Approving Joint Recommendation* in Case Nos. EO-85-185 and EO-85-224 and modified in the November 6, 1992 Order in Case No. EO-93-143, *Order Modifying Joint Recommendation.* The reports include the actual financial results for the preceding 12-months for the reported three-month quarter ending.

Since KCPL operates in two other regulatory jurisdictions, Kansas and the Federal Energy Regulatory Commission ("FERC") for wholesale customers, the quarterly and annual surveillance reports provided to the Commission are for its Missouri operations.

Q. What was KCPL's authorized and actual earned return on equity over time since the prior KCPL rate case, Case No. ER-2014-0370?

A. The table below lists the Commission's authorized return on equity for KCPL's Missouri operations and its actual earned equity returns for the quarters ending December 31, 2014 through the most recent available, September 30, 2016.

Continued on next page

KCPL Surveillance ROE 12 Month Period Ending	Earned Return on Equity	Authorized Return on Equity
December 31, 2014	** _____ **	9.70%
March 31, 2015	** _____ **	9.70%
June 30, 2015	** _____ **	9.70%
September 30, 2015	** _____ **	9.70%
December 31, 2015	** _____ **	9.50%
March 31, 2016	** _____ **	9.50%
June 30, 2016	** _____ **	9.50%
September 30, 2016	** _____ **	9.50%

Rates from Case No. ER-2014-0370 became effective September 29, 2015. KCPL's most recent Missouri earned return on equity was ** _____ **. The Commission authorized the use of the FAC by KCPL in Case No. ER-2014-0370, and the most recent surveillance report includes the impact of a full year of KCPL utilizing the FAC.

Attached to this testimony as Schedule KM-r1 is the Commission authorized return on equity and the actual earned return on equity (ROE) as reported by KCPL in the FAC Quarterly Surveillance Reports accessed on the Commission's Electronic Filing Information System (EFIS). The difference between the authorized and earned return on equity is listed as well. Also listed is GMO's authorized and earned ROE for both MPS and L&P.

Q. Why is GMO's earned ROE relevant in this case?

A. GMO is KCPL's affiliate and adjoining utility. Both KCPL and GMO operate under the Great Plains Energy Inc. ("Great Plains" or "GPE") corporate organization. Both are vertically integrated electric utilities operating in Missouri. Both utilities are under the same management personnel. All employees in Great Plains organization are KCPL

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employees and provide operating services to GMO. GMO recently completed a rate case, Case No. ER-2016-0156. Discussion of inability to achieve its authorized ROE was conspicuously absent from GMO's testimony in <u>that case.</u> ** ____________________

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Q. Have these rates of return been adjusted for any ratemaking normalizations or annualizations?

A. No. These rates of return on equity are taken directly from the quarterly surveillance reports as reported by KCPL and GMO (separately, MPS & L&P). The revenues as reported are not weather-normalized, nor are any of the expenses adjusted from actual results, as opposed to the substantial adjustments made during the ratemaking process. For these reasons, the ROE results reported in the FAC surveillance reports do not necessarily correspond with the revenue requirement calculations used in general rate proceedings to determine whether a utility's rates should be increased or decreased. The surveillance reports reflect actual operating results for KCPL and GMO.

Q. Are Commission authorized ROEs directly comparable to KCPL and GMO actual earned ROEs results reported in the FAC surveillance reports?

A. No. The earned ROE percentages provided in the FAC surveillance reports do not include rate case annualizations and normalizations, which may increase or decrease these figures.

Q. Can you provide an example of an FAC surveillance report ROE that would not be comparable to the Commission authorized ROE, and potentially be understated, due to the lack of rate case processes to adjust, normalize, and annualize?

A. Yes. For example, GMO's FAC surveillance report included disallowed amounts of Crossroads rate base and transmission expense in the reported rate base and expense results. This factor would increase the rate of return, all other things being in equal, in the figures reported by MPS and L&P.

Q. Please explain.

A. In GMO's two prior rate cases, Case Nos. ER-2010-0356 and ER-2012-0175, the Commission ordered disallowances of Crossroads rate base and transmission expenses. In Case No. ER-2016-0156, the case was settled by a Stipulation and Agreement without the Commission making a determination regarding the Crossroads issues. The response to Staff Data Request No. 228, in Case No. ER-2016-0156, noted that all costs, including plant in service, accumulated reserve, depreciation, and transmission expense related to the Commission's disallowances are included at their full value in the GMO surveillance reports.

Q. What is the impact of including Crossroads disallowed expenses in surveillance results?

A. The reported ROEs will be understated compared to rate base ROE calculations that would appropriately reflect the Commission's ordered Crossroads disallowances.

Q. Has Staff recalculated GMO's ROE adjusting for the impact of the Crossroads disallowances?

A. Yes. Attached as Schedule KM-r2 is the response to Staff Data Request No. 0228 in Case No. ER-2016-0156. This response identifies that GMO did not remove the Crossroads disallowances the calculation of the surveillance reports and provides the plant and estimated reserve for the Crossroads disallowance.

Staff Data Request No. 0155.1, Case No. ER-2016-0156 identifies Crossroads transmission expenses separated between MPS and L&P. All Crossroads transmission expenses were disallowed from cost of service in the 2010 and 2012 rate cases.

To calculate the return on equity, Staff removed the estimated Crossroads net plant, from the response to Staff Data Request No. 0228, from the rate base used to calculate the return on rate base. Staff then added back the Crossroads transmission expense to the Net Operating Income line using the response to Staff Data Request No. 0155.1. The recalculated rate of return was then used to calculate the return on equity using the overall cost of capital calculations in the surveillance reports.

Q. What was the return on equity for MPS and L&P adjusted for the Crossroads plant and transmission disallowances?

A. Attached as Highly Confidential Schedules KM-r3 and KM-r4 are the summary and detailed calculations of return on equity from the 12 months ending December 2012 through the 12 months ending June 30, 2016.

Using the recalculated return on equity without the Crossroads disallowances, ** ____

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Q. Can you explain the disparity between GMO's apparent ability to achieve at or near is authorized return and KCPL's apparent inability?

A. Staff has not identified specific disparities between GMO and KCPL that would explain how GMO can earn at or close to its authorized rate of rate of return and KCPL has in the past not been able to achieve its authorized rate of return. The most significant impact since the last KCPL rate case is the Commission's authorization of KCPL's FAC. As can be seen from the surveillance data, with a full year's impact of the FAC, ** ________

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________ **. In comparison to other Missouri electric utilities, KCPL now has an FAC and is on "equal footing" in regards to recovery of those expenses.

Q. Does KCPL claim difficulty in earning its authorized rate of return?

A. Yes. Witness Rush makes this claim in his direct testimony:

> **Q: Do the rate case procedures normally used in Missouri provide a sufficient mechanism for KCP&L to recover the increasing level of costs that it is facing and still earn a fair return on equity?**
>
> A: Unfortunately, no. In an environment where costs are increasing rapidly and certain billing determinants that drive revenues (i.e., per customer kWh sales) are flat to declining, the opportunity for utilities to earn a fair return is severely compromised by regulatory lag.
>
> [Rush Direct, ER-2016-0285, page 3]

Q. Does KCPL rely on returns from surveillance reports to justify alternative ratemaking treatment for some costs?

A. Yes. Throughout the testimony in the current case and Case No. ER-2014-0370, KCPL witnesses repeatedly reference KCPL's past reported returns on equity to justify KCPL's requests for alternative ratemaking for transmission and property tax expense.[1] ** ____ **, the argument that KCPL's actual earned ROE justifies these requests is completely inapt. The Commission has previously rejected the use of a tracking mechanism for these types of on-going operating expenses, and should reject these requests in this case.

REGULATORY LAG

Q. Please describe the phenomenon of "regulatory lag".

A. Regulatory lag is the period of time that elapses between when the time of an event and its related consequences occur and the time the event and its related consequences are reflected in the utility's rates.

Q. How does KCPL seek to address its regulatory lag concerns in this proceeding?

A. As described by KCPL witnesses Heidtbrink, Ives, and Rush, KCPL seeks implementation of several ratemaking mechanisms to reduce its risk associated with regulatory lag and KCPL's alleged compromised ability to earn its authorized return. These mechanisms have been requested by both KCPL and GMO in prior cases, and have been rejected by the Commission.

Q. Please describe how regulatory lag is supposed to work in rate of return regulation.

[1] See Direct Testimony of Scott H. Heidtbrink, page 13, line 16 through page 15, line 14, Direct Testimony of Darrin R. Ives, pages 11 through 17, Direct Testimony of Tim M. Rush, pages 3 through 5.

A. In a utility's operating environment, revenues, expenses, and rate base are constantly changing. In a rate case, a specific test year is selected to develop a utility's revenue requirement based on the most current investments in plant and other shareholder investments in the utility, and a normalized level of revenues and expenses.

Matching the rate base with normalized revenues and expenses creates a revenue requirement that produces a revenue level that allows for the recovery of all of the utility's prudently incurred expenses, and also provides it an opportunity to earn a reasonable rate of return on the investment in its regulated rate base. To the extent normalized revenues fall short of total revenue requirement, an increase ("rate increase") is warranted. To the extent normalized revenues exceed total revenue requirement, a decrease ("rate reduction") is warranted. Once the Commission orders a change in rates, a long list of variables come into play that affect a utility's ability to earn at the authorized level established by the Commission.

Q. What are examples of these variables?

A. One example is when a utility is not currently engaged in a large amount of construction or adding a large amount of new plant additions to its rate base. During this period, due to the rate recovery of its plant investment through depreciation expense and the resulting increases in depreciation reserve offset to rate base, shareholder investment in regulated rate base is constantly declining. However, while the utility's actual rate base is smaller, the overall rate of return is based on the larger rate base that was fixed in rates in the previous rate case, resulting in a larger than required financial return to the utility, all other things being equal.

This larger-than-required financial return paid by a utility's ratepayers is the result of regulatory lag. This regulatory lag, resulting from a declining rate base, results in the utility's investors recovering more of a financial return on the rate base in utility rates than was determined reasonable and set in rates in the previous rate case.

Q. In addition to a declining rate base, what other factors may result in a positive regulatory lag?

A. Increases in efficiency and advances in technology can result in significant cost reductions as well as positive regulatory lag that can offset negative regulatory lag associated with increases in fuel or other expenses.

Employee reductions through attrition or voluntary separations can be a cost savings. Each employee reduction below the level of employees reflected in rates represents a cost savings until rates are changed. In addition to this payroll expense, all employee benefit costs that are included in rates that are associated with positions no longer filled would be retained as a significant savings. Those reduced employee costs offset increases in costs in other cost categories.

Q. Are there public policy benefits associated with the existence of regulatory lag as part of cost of service rate regulation?

A. Yes. Utilities in Missouri have been granted exclusive rights to provide their services within their designated service territories, allowing them to act as monopolies. Regulatory lag creates the "quasi-competitive environment" for utilities, similar to the environment in which competitive firms operate. Without trackers and other types of single-issue ratemaking mechanisms to rely upon, utility managers have a strong incentive to keep costs as low as possible once rates are set in a rate case to maintain their earnings as close to a reasonable return as possible.

This is the same incentive encountered by any manager of a business who strives to operate the business more efficiently and profitably. Just as competitive firms cannot raise prices of their goods and services at will, regulatory lag places this same constraint on utilities. Due to the existence of regulatory lag, utility managers must work under the constraint of a "fixed price" or regulatory lag for a period of time.

The existence of this fixed price incentive or regulatory lag incentive causes utility managers to work like managers of competitive businesses. Both utility managers working with regulatory lag and managers of competitive businesses working with fixed prices of goods and services seek to find ways to operate the business more efficiently to counteract expense or rate base increases or potential revenue decreases during the period of time of when prices are fixed, or regulatory lag. Conversely, utilities benefit from regulatory lag when expenses or rate base decrease or when revenues increase while rates remain unchanged. This is exactly why regulatory lag is a critical ingredient in cost of service rate regulation.

Q. What is KCPL's position concerning regulatory lag in this case?

A. KCPL believes it has not had opportunity to earn its authorized return on equity because of regulatory lag. Mr. Ives states at page 12 of his direct testimony:

> First and foremost, the regulatory model in Missouri is built primarily on historical financial information. From a cost of service perspective, the process utilizes historical test year costs, trued-up for known and measurable changes. Regardless of the true-up period, this model results in rates being set on historical costs that were incurred in a range anywhere from 5 months to 27 months prior to the date rates are effective. This model ignores cost increases that have occurred between the historical test year used and the date rates are effective, and also ignores the fact that in a rising cost environment, costs to serve our customers continue to increase from the date rates are effective, with

> little ability to synchronize recovery with costs incurred other than to initiate another expensive and time-consuming rate case.

Mr. Ives' statement is a one sided view of the rate making process in Missouri.

Q. KCPL witness Ives asserts that Missouri's use of historical information for setting utility rates results in harmful regulatory lag. Do you agree?

A. No. While in Missouri, actual historical costs are used as the starting point for determining what a utility's future cost to serve its retail customers is; those historical costs are normalized and annualized when appropriate to reflect the most current information available. Adjustments for known and measurable changes are made to the test year, in this case the 12 months ending December 31, 2015, through June 30, 2016. These adjustments are further trued-up through December 31, 2016, five months before the effective date of rates, May 28, 2017.

Q. KCPL believes it is unable to earn its authorized return because rates are developed using historical cost information incurred as far back as 27 months from the date new rates take effect, according to Mr. Ives. Does Staff agree with this assessment?

A. No. The test year is a starting point for all costs. It is incumbent upon KCPL, and any utility, to identify known cost increases (and decreases) when filing its rate case and throughout the rate case process, although there is less incentive to identify cost decreases. Only through the Company's workpapers and the discovery process does Staff gain knowledge of cost increases and decreases. KCPL has absolute knowledge of what costs are increasing or decreasing. While the majority of costs such as fuel and purchased power, payroll, and property taxes are included in the cost of service calculation at current levels, under certain circumstances, test year levels are deemed appropriate and no adjustments are proposed. This means when a cost is left at test year level, it is believed those costs represent the level necessary for those expenditures going forward. Just because a cost is based on historical actual cost does not mean those costs are "dated" or somehow not reflective of on-going costs and cannot be used to set rates. The fact that the cost data is up to 27 months old is irrelevant if it is representative of ongoing costs. For costs that are normalized and annualized, cost information is updated as of June 30, 2016 and trued-up as of December 31, 2016. At most there is a five month lag for known and measurable cost increases that are not subject to a tracker or single issue ratemaking.

Q. Are annualized costs the same thing as historical costs?

A. No, but they are based on known and measurable historical information. While actual cost inputs are used as the basis to develop the levels of costs included in rates, the annualized levels of costs are by no means always historical costs. There are four specific examples of costs that are not historical:

- Delivered coal (commodity costs and freight) and nuclear fuel
- Property Taxes
- Base Payroll (salaries and wages)
- Southwest Power Pool ("SPP") Schedule 1A Administrative Fees

These four expenses are some of the expenses that are updated in Staff's true-up.

Q. How does Staff annualize delivered coal and nuclear fuel costs in this case?

A. In the true-up in this case, Staff will use actual contracted January 1, 2017 coal and freight prices to reflect both increases and decreases based on existing fuel and freight contracts. These prices are actual contracted prices and do not in any way relate to historical costs from the test year or prior to the true-up. Using these prices will produce an annualized fuel cost level that is not the same as historical test year fuel cost results, but rather the actual cost basis going forward. Annualized fuel costs in this case will have no relationship to test year costs, nor calendar year 2016 fuel costs. In addition, the latest price for nuclear fuel is used, which may or may not differ from the actual costs in the test year or through the true-up. In both cases, the costs are not historical costs, but are the going forward costs as of the true-up.

Q. How does Staff annualize property taxes in this case?

A. Staff derives property taxes first by identifying the ratio of property taxes to assessed property. In Staff's direct filed case, Staff divided the property taxes paid during the test year ending 2015 by the assessment date (January 1, 2015) to obtain the ratio. Staff then applied this percentage to the January 1, 2016 assessed plant amounts to determine the annualized cost. As of the true-up, Staff will update this ratio for property taxes paid during 2016 compared to the assessed plant as of January 1, 2016. Staff will apply this updated ratio to the January 1, 2017 plant to annualize property tax expense. KCPL will not actually pay this amount of property taxes as of true-up, and this amount will not be due until December 31, 2017, 12 months after the true-up date in this case and 7 months past the effective date of rates. Staff's method of annualizing property taxes is clearly not based on historical costs as Mr. Ives opines.

Q. How does Staff annualize base payroll costs in this case?

A. Payroll costs are determined the same way as fuel costs by using actual cost employee levels and the most current wage rates to determine annualized payroll costs as of December 31, 2016, in Staff's true-up. Again, these costs have no relationship to what KCPL actually paid during 2015 or 2016; they are based on costs at the most recent available known and measurable point in time.

Q. How does Staff annualize SPP administrative fees in this case?

A. Staff applies the current SPP administrative fee rate to the previous years' retail load and point-to-point transmission volume. Staff uses the most current fee rate to annualize the expense. In KCPL's direct workpapers, KCPL used 38.4 cents ($0.384) per megawatt hour to annualize this expense. The new fee rate as of January 1, 2017 will be 41.9 cents ($0.419) per megawatt hour. The test year expense with the prior administrative fee rate will have no relationship to the ongoing expense. Contrary to Witness Ives' testimony, this expense is not a historical expense.

Q. What happens when regulatory lag is reduced or eliminated through the use of expense trackers or other single-issue ratemaking mechanisms?

A. When the use of trackers and other single-issue ratemaking mechanisms eliminate the "quasi-competitive" forces of regulatory lag on components of the cost of service, utility managers are no longer under the same level of pressure to act as efficiently and to keep expenses as low as possible. Expenses are now tracked, and recovery of the tracked expense is virtually guaranteed. This reduced level of quasi-competitive pressure can result in utility inefficiencies and ultimately could lead to imprudent utility management behavior.

Q. What single-issue ratemaking mechanisms exist to reduce regulatory lag?

A. There are several mechanisms that KCPL has used or is available for KCPL to use to reduce its regulatory lag:

- Fuel Adjustment Clause ("FAC")
- Missouri Energy Efficiency Investment Act ("MEEIA") surcharge
- Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM")
- Environmental Cost Recovery Mechanism ("ECRM")

Q. In his rebuttal testimony, Witness Ives identifies transmission and property tax expenses as items for which KCPL requests a tracker, and identifies these costs as increasing. Do other cost of service items increase year to year?

A. Yes, they do. For example, salary and wage costs for KCPL have increased by 2-3% per year for some time, for merit and internal promotions. All other things being equal, this cost increase would increase overall expense and decrease earnings. However, all other things are not equal in this instance. Workforce attrition is the net loss of a headcount when an employee retires or is separated and not replaced. Workforce turnover can reduce the costs per employee when younger, less experienced workers that earn less replace older workers. For bargaining unit positions, these reductions also impact overtime expense. These reductions serve to offset and mitigate the merit and promotion increases.

Isolating known increasing costs such as transmission expenses and property taxes ignores other non-tracked costs that can decrease and mitigate those increases.

Q. Has KCPL been able to achieve interest savings on debt?

A. Yes. KCPL has been able to refinance a substantial portion of its long term debt, achieving significant savings in interest expense. KCPL has identified the opportunity for substantial interest savings resulting from future refinancing opportunities. KCPL identified these savings in the response to MECG Data Request 3-5, attached as Schedule KM-r5. The table below details the actual savings and future potential annual savings based on current 10 and 30 year indicative rates:

Date Refinanced	**Debt Instrument**	**Prior Rate**	**New Rate**	**Annual Savings**
November 2011	Senior Notes - $150 million	6.50%	5.30%	$1.8 million
2011 through 2016	Tax Exempt Bonds - $265.9 million	5.30%	1.86%	$8.7 million
			Total Annual Savings	$10.5 million

The following are potential interest savings based on future refinancing:

Potential Refinance Date	Debt Instrument	Prior Rate	New Rate - 10 year	Annual Savings
June 2017	Senior Notes - $250 million	5.85%	2.86%	$7.475 million
March 2018	Senior Notes - $350 million	6.375%	2.86%	$12.3 million
April 2019	Mortgage Bonds - $400 million	7.15%	2.86%	$17.16 million
			Total Annual Savings	$36.9 million

Potential Refinance Date	Debt Instrument	Prior Rate	New Rate - 30 year	Annual Savings
June 2017	Senior Notes - $250 million	5.85%	3.83%	$5.05 million
March 2018	Senior Notes - $350 million	6.375%	3.83%	$8.9 million
April 2019	Mortgage Bonds - $400 million	7.15%	3.83%	$13.28 million
			Total Annual Savings	$27.2 million

The June 2017 refinancing is past the true-up date and effective date of rates in this case. KCPL will able to retain any interest savings related to this financing, and can do so until a rate case is filed that reflects the reduced interest costs.

Q. Are there other cost reductions KCPL does not consider in its discussion of regulatory lag?

A. Yes. KCPL has had significant cost reductions in its cost of service for increased accumulated deferred income taxes, or deferred taxes. Deferred taxes are accounted for as an offset to rate base. Since the rate base determined by the Commission in its order in Case No. ER-2014-0370, deferred taxes have increased $67.3 million; from $646.9 million at

May 31, 2015 true-up levels to $714.2 million through June 30, 2016, the update period in this case. The decrease in rate base for deferred taxes is an approximately $6.7 million to $10 million savings to the revenue requirement on a Missouri jurisdictional basis (assuming a 10% to 15% rate base conversion). Deferred taxes will further increase for the true-up in this case at December 31, 2016.

Q. GPE, KCPL's parent company, announced the acquisition of Westar Energy, Inc. on May 31, 2016. If the acquisition is completed, how would this event create cost savings?

A. GPE has announced expected benefits of approximately $65 million in year 1 and improving to $200 million in year 3 and beyond.[2] Like reductions in interest cost and payroll reductions, a portion of these synergies will be retained by KCPL until they are reflected in rates. It is noteworthy that KCPL does not seek a tracker or other deferral mechanism to track these significant cost reductions, but has sought and continues to seek isolated trackers for selected increasing costs.

Q. Has KCPL received benefits that suggest that it has a good regulatory climate to operate in, contrary to Mr. Ives' view?

A. Yes. Both KCPL and GMO have received recent upgrades to its credit ratings. The minutes to the GPE, KCPL, and GMO's Board of Directors meeting and the minutes to the Audit Committee of the Boards of GPE, KCPL, and GMO meetings identified reasons for the credit rating upgrades by the analysts. Mr. Kevin E. Bryant, then Great Plains and KCPL's Vice President- Investor Relations and Strategic Planning and Treasurer made a presentation to the Board of Directors to each of the GPE companies:

[2] See Great Plains Energy Investor Presentation Dated September 2016, page 7.

> Mr. Bryant discussed Moody's recent one notch credit rating upgrades of Great Plains Energy, KCP&L and KCP&L Greater Missouri Operations Company ("GMO"). **Moody's cited a constructive regulatory environment that continues to provide adequate cost recovery as one of their rationales for the upgrade.** [Source: Great Plains, KCPL and GMO February 10-11, 2014 Board Minutes; emphasis added]

Mr. Bryant also addressed the constructive regulatory nature of the Missouri Commission at the May 5, 2014 Audit Committee of the Great Plains Board identified in the minutes to that meeting:

> Mr. Bryant indicated that in January 2014, Moody's upgraded Great Plains Energy, KCP&L and KCP&L Greater Missouri Operations ("GMO") by one notch, citing constructive regulatory relationships in Missouri and Kansas. In May 2014, Standard & Poor's Rating Services ("S&P") also raised the credit ratings of Great Plains Energy, KCP&L and GMO by one notch **due to continuation of the regulated utility business model with supportive cost recovery.** [Source: Great Plains, KCPL and GMO May 5, 2014 Board Minutes of the Audit Committee; emphasis added]

In the Great Plains Energy Incorporated ("Great Plains") 2014 Annual Report to Shareholders[3] it was stated that ". . . efforts to strengthen key-credit metrics and further solidify our credit profile were validated by ratings upgrades by both Standard and Poor's and Moody's Investor Service. These ratings reduce borrowing costs, which also help us manage customer rates."

[3] 2014 Great Plains Energy Annual Report, pg. 2, located at *http://phx.corporateir.net/phoenix.zhtml?c=96211&p=irol-reportsannual.*

Q. Has the Commission previously addressed the subject of regulatory lag?

A. Yes. The Commission has found it is not reasonable to protect shareholders from all regulatory lag. In 1991, Missouri Public Service, a division of UtiliCorp United Inc., the predecessor company of GMO, requested an accounting authority order ("AAO"), in Case Nos. EO-91-358 and EO-91-360. In its Order, the Commission stated in part:

> **Lessening the effect of regulatory lag by deferring costs is beneficial to a company but not particularly beneficial to ratepayers.** Companies do not propose to defer profits to subsequent rate cases to lessen the effects of regulatory lag, but insist it is a benefit to defer costs. Regulatory lag is part of the regulatory process and can be a benefit as well as a detriment. Lessening regulatory lag by deferring costs is not a reasonable goal unless the costs are associated with an extraordinary event.
>
> Maintaining the financial integrity of a utility is also a reasonable goal. The deferral of costs to maintain current financial integrity, though, is of questionable benefit. If a utility's financial integrity is threatened by high costs so that its ability to provide service is threatened, then it should seek interim rate relief. **If maintaining financial integrity means sustaining a specific return on equity, this is not the purpose of regulation. It is not reasonable to defer costs to insulate shareholders from any risks. If costs are such that a utility considers its return on equity unreasonably low, the proper approach is to file a rate case so that a new revenue requirement can be developed which allows the company the opportunity to earn its authorized rate of return.** Deferral of costs just to support the current financial picture distorts the balancing process used by the Commission to establish just and reasonable rates. Rates are set to recover ongoing operating expenses plus a reasonable return on investment. Only when an extraordinary event occurs should this balance be adjusted and costs deferred for consideration in a later period.[4] [emphasis added]

Q. What is the conclusion from your testimony on regulatory lag?

[4] MPSC vol 1, 3d 207.

A. Staff does not dispute the fact KCPL has experienced a level of cost increases from the cost of service level determined from the last rate case. It is common for a utility seeking rate relief to experience increased costs or expect to increase costs, often due to increases in rate base due to plant additions, or cost increases for such items as transmission and fuel costs. However, KCPL has presented a very limited and one-sided analysis respecting its view of regulatory lag in its direct testimony. The Company is quick to point out all the costs that have increased since its last rate case. But KCPL has ignored any cost reductions that have occurred since the rates determined in KCPL's 2014 rate case have been in effect. Staff, in presenting the rebuttal testimonies of various witnesses, is attempting to identify some of the cost savings and benefits KCPL has not recognized in its request concerning regulatory lag and the deferral mechanisms. Staff disputes the need for these various single issue ratemaking mechanisms requested by the Company in this case. To the extent costs are increasing faster than cost benefits creating positive revenue requirements, KCPL should request a change in its rates after maintaining strenuous efforts towards cost containment. If KCPL really believed it is not earning a reasonable and fair return for its shareholders, then it should have filed for rate relief much earlier than it did.

The regulatory model used in Missouri is not broken or somehow obsolete. It has worked well for over a century, as evidenced by the healthy financial condition KCPL finds itself and recognized by the rating agencies, who early last year increased KCPL's and GMO's credit ratings, specifically citing the constructive regulatory support from the Missouri Commission as reason for this increase.

SEC 10-K EARNINGS AND UTILITY INDUSTRY AVERAGE ROE

Q. Earlier, you identified KCPL's ROE according to the surveillance reports filed with the Commission. Is there another ROE the Commission should consider?

A. Yes. Using data publicly available in KCPL's Securities and Exchange Commission ("SEC") Form 10-K, I calculated KCPL reported ROE using net income available for common stockholders as the numerator and the average of KCPL's beginning and ending common stock equity as the denominator. I have attached my calculations as Schedule KM-r6.

There are a few caveats to using this ROE information, as KCPL identified to the Commission in ER-2014-0370:

- The data includes both Kansas and Missouri jurisdictions. KCPL Kansas is a separately regulated jurisdiction.
- The publicly available SEC common equity balances are not the same as those listed on the surveillance reports.
- The results from are unadjusted actual results not subject to ratemaking normalizations and annualizations done in a rate proceeding.

Q. With the above caveats in mind, why do you believe this method of calculating ROE is relevant?

A. First, like the surveillance reported ROE, both sets of data show that KCPL has the ability to earn a reasonable rate of return compared to the awarded ROE throughout the electric utility industry, and has in the past. The testimony will address this in a later section. During the period 1993 through 2007, KCPL earned above the industry average rate of return, with the exceptions of 1997 and 1999, in comparison to the SEC ROE. Using the 1997 surveillance data, KCPL earned above the industry average.

Furthermore, using the SEC ROE presents a more complete picture of financial health of KCPL.

Q. What electric industry ROE comparison did you use, and what were the results of that comparison?

A. I used the Edison Electric Institute ("EEI") "Rate Case Summary" for the quarter ending 2015. This data set lists the average awarded ROE from 1993 through 2015. I have attached the source document as Schedule KM-r7. I compared the EEI average ROE to KCPL's Missouri Authorized ROE for 1993 through 2015:

Year	EEI - Average Electric Utility Authorized ROE	KCPL MO Authorized ROE	Difference
1993	11.42%	15.00%	3.58%
1994	11.55%	15.00%	3.45%
1995	11.56%	15.00%	3.44%
1996	11.31%	15.00%	3.69%
1997	11.44%	15.00%	3.56%
1998	11.87%	15.00%	3.13%
1999	10.80%	15.00%	4.20%
2000	11.57%	15.00%	3.43%
2001	11.15%	15.00%	3.85%
2002	11.07%	15.00%	3.93%
2003	10.92%	15.00%	4.08%
2004	10.83%	15.00%	4.17%
2005	10.52%	15.00%	4.48%
2006	10.30%	15.00%	4.70%
2007	10.26%	11.25%	0.99%
2008	10.34%	10.75%	0.41%
2009	10.47%	10.75%	0.28%
2010	10.29%	Settlement	
2011	10.25%	10.00%	-0.25%
2012	10.15%	10.00%	-0.15%
2013	9.99%	9.70%	-0.29%
2014	9.93%	9.70%	-0.23%
2015	9.78%	9.70%	-0.08%

The data set above shows the EEI electric utility average authorized return compared to KCPL's authorized return. Through 2006, KCPL's authorized return was substantially higher than the EEI electric utility average authorized return.

The table below details the SEC ROE, the surveillance ROE, and the EEI industry average.

Year	KCPL SEC ROE, Avg. Balance	EEI - Average Electric Utility Authorized ROE	Difference (KCPL SEC ROE minus EEI Average)	KCPL MO Jurisdictional ROE, Surveillance Reports	Difference (KCPL MO ROE minus EEI Average
1993	11.93%	11.42%	0.51%	12.30%	0.88%
1994	11.64%	11.55%	0.09%	11.67%	0.12%
1995	13.38%	11.56%	1.82%	NA	NA
1996	11.54%	11.31%	0.23%	NA	NA
1997	8.14%	11.44%	-3.30%	12.90%	1.46%
1998	13.20%	11.87%	1.33%	14.13%	2.26%
1999	8.90%	10.80%	-1.90%	10.07%	-0.73%
2000	17.59%	11.57%	6.02%	8.26%	-3.31%
2001	14.24%	11.15%	3.09%	11.17%	0.02%
2002	12.85%	11.07%	1.78%	13.55%	2.48%
2003	14.64%	10.92%	3.72%	12.20%	1.28%
2004	14.76%	10.83%	3.93%	11.57%	0.74%
2005	12.70%	10.52%	2.18%	10.3%, revised for 4 CP Demand	-0.22%
2006	11.78%	10.30%	1.48%	8.6%, revised for allocations	-1.70%
2007	10.95%	10.26%	0.69%	10.04%	-0.22%
2008	8.07%	10.34%	-2.27%	7.69%	-2.65%
2009	7.25%	10.47%	-3.22%	6.15%	-4.32%
2010	8.29%	10.29%	-2.00%	6.91%	-3.38%
2011	6.69%	10.25%	-3.56%	5.09%	-5.16%
2012	6.84%	10.15%	-3.31%	5.84%	-4.31%
2013	7.90%	9.99%	-2.09%	6.49%	-3.50%
2014	7.29%	9.93%	-2.64%	5.69%	-4.24%
2015	6.48%	9.78%	-3.30%	5.25%	-4.53%

Q. Do you believe that positive regulatory lag contributed to KCPL's earnings over the 15-year period (1993-2007), exceeding the average ROE authorized for electric utilities in the United States in all except two years?

A. Yes. During this period, regulatory lag worked without manipulation and contributed to KCPL enjoying high levels of shareholder profit. I would also add that in comparison to KCPL's surveillance ROE, there were some years higher and some lower than the average awarded ROE.

Q. Does KCPL consider its ROEs during this period to be reasonable?

A. Yes, I believe it does. I would note that KCPL made no regulatory requests before the Commission to increase its rates during the period 1993 through 2005, nor did KCPL propose a tracker or other single issue ratemaking mechanism that would serve to return or track any of the earnings levels during this period. In fact, KCPL's rates were lowered several times during the 1990s. If KCPL felt its earnings were unreasonable during this time, I believe it had a responsibility to its customers to seek an adjustment to any rates that it considered unreasonable. Since I also do not believe that KCPL's profit levels were unreasonable, I do not think that KCPL should have sought any adjustment to its rates during this period.

Q. Is the KCPL authorized ROE from 1993 through 2005 of 15% representative of a realistic ROE in Missouri for that time period?

A. No. The 15% authorized return on equity was granted by the Commission in its April 1986 Order in Case No. ER-85-185, KCPL's 1985 rate case— the case in which the Commission authorized the inclusion of Wolf Creek Nuclear Generating Station in rates.

Q. What ROEs were awarded to Missouri electric utilities between 1985 and 2006?

A. There are several examples:

- EC-87-114 and EC-87-115 – *The Staff of the Missouri Public Service Commission, Complainant, vs. Union Electric Company, Respondent*. The Commission's *Report and Order* dated December 21, 1987 found: "Based on the competent and substantial evidence, and the considerations set forth above, the Commission finds that the Company's authorized return on equity shall be **12.01 percent**, resulting in an overall cost of capital of 9.94 percent." Public Service Commission Reports, New Series, Vol. 29, page 339. [emphasis added]

- ER-90-101 – *In the matter of Missouri Public Service for authority to file tariffs increasing rates for electric service provided to customers in the Missouri Service area of the company.* The Commission's *Report and Order* dated October 5, 1990 found: "However, the Commission determines that the top end of Staff/Public Counsel's recommended range for return on equity **(12.84 percent)** should be adopted in order to insure that Company has sufficient capital available to complete its construction program." Public Service Commission Reports, New Series, Vol. 30, page 357. [emphasis added]

- ER-93-37 – *In the matter of Missouri Public Service, a division of Utilicorp United, Inc., proposed tariffs to increase rates for electric service provided to customers in the Missouri service area of the Company.* The Commission's *Report and Order On Rehearing* dated February 25, 1994 found: "The Commission, though, finds that the evidence would support an ROE for MPS of at least within the range of **11.07 percent to 11.55 percent**." Public Service Commission Reports Vol.2, MPSC 3d, page 243. [emphasis added]

- ER-93-41 – *In the matter of St. Joseph Light & Power Company's proposed tariffs to increase rates for electric service provided to customers in the Missouri service area of the Company.* The Commission's *Report and Order* dated June 25, 1993 found: "The Commission, for these reasons, determines that Staff's rate of return on equity is the appropriate one upon which to base its decision. In that contest, the Commission further determines **11.67%** should be adopted as the most just and reasonable return on equity." Public Service Commission Reports Vol.2, MPSC 3d, page 255. [emphasis added]

- ER-97-394 – *In the Matter of Missouri Public Service, a Division of UtiliCorp United Inc.'s Tariff Designed to Increase Rates for Electric Service to Customers in the Missouri Service Area of the Company.* The Commission's *Report and Order* dated March 6, 1998 found: "The Commission, therefore, adopts a return on equity for use in this case of **10.75 percent**." Public Service Commission Reports Vol.7, MPSC 3d, page 184. [emphasis added]

- ER-2001-299 – *In the Matter of The Empire District Electric Company's Tariff Sheets Designed to Implement a General Rate Increase for Retail Electric Service Provided to Customers in the Missouri Service Area of the Company.* The

Commission's *Report and Order* dated September 20, 2001 found: "The Commission finds that the appropriate rate of return on common equity is **10.00%**." Public Service Commission Reports Vol.10, MPSC 3d, page 474. [emphasis added]

Q. Can you summarize these cases and their awarded ROEs?

A. Yes, see the table below:

Case No.	Date	Return on Equity
EC-87-114 & EC-87-115	December 1987	12.01%
ER-90-101	October 1990	12.84%
ER-93-37	February 1994	11.07-11.55%
ER-93-41	June 1993	11.67%
ER-97-394	March 1998	10.75%
ER-2001-299	September 2001	10.00%

Compared to the authorized return of 15%, these returns are substantially lower and more representative of what an authorized return would have been had KCPL filed a rate case during this time period.

<u>FINANCIAL MARKET'S VIEW OF KCPL AND MISSOURI REGULATORY ENVIRONMENT</u>

Q. What sources have you used to gauge the financial market's view of KCPL and Missouri regulation, in light of the claims made by KCPL?

A. I reviewed these documents attached to this testimony, and will discuss them:

- SNL Financial Missouri Public Service Commission Profile, accessed December 27, 2016, Schedule KM-r8
- S&P Global Ratings Research Update, dated May 31, 2016, Schedule KM-r9
- S&P Global Ratings KCPL Summary, dated June 17, 2016, Schedule KM-r10
- SNL Energy Financial Focus, Great Plains Energy, dated January 11, 2016, Schedule KM-r11

- Regulatory Research Associates Regulatory Focus, dated October 18, 2016, Schedule KM-r12

Q. Please explain the first document.

A. SNL Financial Missouri Public Service Commission Profile is the Commission's general profile and description. The report specifically notes "Historically, Missouri regulation has been relatively balanced from an investor perspective." The report lists the Commission's ranking in relation to other Commissions as "Average / 2", which is described as a "mid-range" rating in the "Average" category. In fact, since 1982 as listed in this document, "Average / 2" is the highest ranking.

Q. Please explain the second document.

A. The S&P Global Ratings Research Update is a document released by Standard & Poor's to affirm GPE's credit ratings. In the document, S&P stated the following concerning the regulatory environment in which GPE operates:

> **We view GPE's business risk as excellent**, which incorporates the very low risk of a regulated utility focused on U.S. operations and markets. In addition, the business risk profile reflects a competitive position based on utility subsidiaries KCP&L, which serves about 527,000 electricity customers in and around Kansas City and its suburbs, and GMO, which serves about 300,000 electricity customers in western Missouri. **The company operates with generally supportive regulation**, a mainly residential customer base that supports cash flow stability good operating efficiency, and an absence of competition. Riders and mechanisms exist for the recovery of fuel costs, transmission charges, and energy-efficiency costs. GPE continues to focus on a regulated business strategy in pursuing similarly regulated Westar. [emphasis added]

Q. Please explain the third document.

A. The S&P Global Ratings KCPL Summary is a document released by Standard & Poor's to describe KCPL's regulatory environment, key metrics, and risk profile. Some key points in the document:

> **"The regulatory framework in Kansas and Missouri is generally supportive"**
>
> ...
>
> Business Risk: Excellent
> We base our assessment of KCP&L's business risk profile on what we view as the company's strong competitive position, very low industry risk stemming from the regulated utility industry, and the very low country risk stemming from the utility's U.S.-based operations. **KCP&L's competitive position reflects the company's fully regulated integrated electric utility operations and our expectation for continued solid operational performance and generally credit-supportive regulation**. The utility serves about 527,000 retail customers mainly in the greater Kansas City metropolitan area. The competitive position is also supported by an economically healthy service territory centered on a single metropolitan area with little industrial concentration, solid nuclear power operations, very low fuel costs, and lower electric rates. These attributes are partially offset by nuclear risks associated with the 47%-owned Wolf Creek station. **The utility now operates with generally supportive regulation**, cash flow stability from its customer base, and no competition.
> [emphasis added]

Q. Please explain the fourth document.

A. The SNL Energy Financial Focus, Great Plains Energy is a company profile of GPE identifying key financial, generation, and customer metrics. Most importantly, this document states on page 2: "The Missouri regulatory environment, still traditionally regulated, has been relatively balanced from an investor perspective."

Q. Please explain the fifth document.

A. This document lists the evaluation results of the regulatory commissions from all 50 states and the District of Columbia by Regulatory Research Associates, a division of

SNL. This document ranks commissions on numerous factors, and the rankings are "subjective and are intended to be comparative in nature". There are some important facts in this document:

- Missouri is ranked "Average / 2". This is the most common ranking with 15 other states sharing this ranking.

- Kansas is also ranked "Average / 2". KCPL touts the regulatory climate in Kansas more supportive than Missouri, but Kansas shares the same ranking as Missouri despite Kansas' numerous one-sided single-issue ratemaking mechanisms.

- Illinois is ranked "Below Average / 1". The Illinois regulatory climate is one of deregulation, unbundled rates (separate generation, transmission, and distribution utilities and rates), and formula rates, yet it is ranked two positions lower than Missouri.

- Of the eight states that border Missouri, three of the eight states (Iowa, Kentucky, and Tennessee) are rated higher than Missouri. Four (Arkansas, Kansas, Nebraska, and Oklahoma) share the same ranking, and Illinois is ranked lower.

Q. What can be surmised concerning these documents?

A. Contrary to Witness Ives' testimony on Missouri regulation, the financial markets view Missouri regulation in a positive light:

- Missouri is ranked "Average / 2", after the Commission rejected KCPL's tracker requests in ER-2014-0370. This ranking is the same as Kansas and higher than Illinois. The "Average / 2" ranking is the same ranking Missouri received in ratings before the Commission authorized KCPL's FAC in the 2015 rate case. The Missouri Commission ranking did not change from "Average / 2" since approving KCPL's FAC.

- Missouri is described as having generally supporting regulation.

TRANSOURCE MISSOURI ADJUSTMENTS

Q. What adjustments related to Transource Missouri are you addressing in this rebuttal testimony?

A. I address KCPL Adjustment CS-108 "Transource CWIP/FERC Incentives." This adjustment was sponsored by KCPL witness Ronald A. Klote on page 55 of his direct testimony. Mr. Klote describes this adjustment, in part, as follows:

> Adjustment CS-108 reflects a change to Account 565 - Transmission of Electricity by Others that represents the difference between KCP&L's SPP load ratio share allocation of Transource Missouri's annual transmission revenue requirement ("ATRR") for the Iatan Nashua and Sibley-Nebraska City Projects and KCP&L's SPP load ratio share allocation of the ATRR for the [Iatan] Nashua and Sibley-Nebraska City Projects if it had been calculated utilizing KCP&L's MPSC-authorized ROE and capital structure and did not include the FERC-authorized rate treatments and incentives listed above.

Q. What is Transource Missouri?

A. Transource Missouri is a Delaware limited liability corporation qualified to conduct business in Missouri, with its principle place of business in Columbus, Ohio. Transource Missouri is a wholly-owned subsidiary of Transource Energy, LLC ("Transource"). Transource was established by Great Plains Energy Incorporated ("GPE"), KCPL's parent corporation, and American Electric Power Company, Inc. ("AEP") to build wholesale regional transmission projects within Southwest Power Pool ("SPP"), as well as other regional transmission organizations.

Q. Why is this adjustment necessary?

A. This adjustment is made to comply with the provisions of the Commission's *Report and Order* in File No. EA-2013-0098.[5] Ordered item "5" states "Ordered paragraphs 1, 2, 3 and 4 are subject to the provisions of Appendix 3 and Appendix 4." "Appendix 4: Consent Order" starts on page 26 of the Report and Order, and on pages 27-28 under paragraph 2.A 1. appears the following language:

> 2.A.1. With respect to transmission facilities located in KCP&L certificated territory that are constructed by Transource Missouri that are part of the Iatan-Nashua and Sibley-Nebraska City Projects, KCP&L agrees that for ratemaking purposes in Missouri the costs allocated to KCP&L by SPP will be adjusted by an amount equal to the difference between: (a) the SPP load ratio share of the annual revenue requirement for such facilities that would have resulted if KCP&L's authorized ROE and capital structure had been applied and there had been no Construction Work in Progress ("CWIP") (if applicable) or other FERC Transmission Rate Incentives, including but not limited to Abandoned Plant Recovery, recovery on a current basis instead of capitalizing pre-commercial operations expenses and accelerated depreciation, applied to such facilities; and (b) the SPP load ratio share of the annual FERC-authorized revenue requirement for such facilities. KCP&L will make this adjustment in all rate cases so long as these transmission facilities are in service.

This paragraph is identical to Paragraph II A. 1. on pages 4-5 of the *Non-Unanimous Stipulation and Agreement* filed in File Nos. EA-2013-0098 and EO-2012-0367[6] consolidated.

Q. Please describe File Nos. EA-2013-0098 and EO-2012-0367.

[5] In the Matter of the Application of Transource Missouri, LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Finance, Own, Operate, and Maintain the Iatan-Nashua and Sibley-Nebraska City Electric Transmission Projects

[6] In the Matter of the Application of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company for Approval To Transfer Certain Transmission Property to Transource Missouri, LLC and for Other Related Determinations

A. These applications were filed simultaneously by Transource Missouri, KCPL, and GMO.

File No. EO-2012-0367 was an application for authority to transfer certain transmission property and for other related determinations regarding the construction of two regional, high-voltage, wholesale transmission projects approved by SPP known as the Iatan-Nashua 345kV transmission project ("Iatan-Nashua Project") and the Sibley-Nebraska City 345kV transmission project ("Sibley-Nebraska City Project;" collectively, the "Projects").

File No. EA-2013-0098 was an application for line Certificates of Convenience and Necessity ("CCNs") to construct, finance, own, operate, and maintain the regional Projects ("CCN Application") for Transource Missouri.

The *Report and Order* in File No. EA-2013-0098 approved both the transfer of assets to Transource Missouri and the CCNs for Transource Missouri, with certain provisions, one of which is the aforementioned paragraph describing the adjustment at issue.

Q. How is this adjustment calculated?

A. Both KCPL and GMO have FERC-approved formula rates that have been incorporated into the SPP Tariff. These wholesale transmission rates are often referred to as "formula rates" because the Annual Transmission Revenue Requirement ("ATRR") for the applicable transmission owner is determined through the use of an agreed-upon formula that incorporates annual true-up processes to update actual costs. Transource Missouri also has a filed ATRR before the FERC that is collected pursuant to SPP Tariff.

The adjustment being addressed is calculated by capturing the difference between the actual ATRR calculated for the transmission facilities and the ATRR calculated for the facilities not using FERC approved incentives in Transource Missouri's ATRR. The difference between these two ATRRs is subtracted from FERC Account 565 in KCPL's cost of service.

Q. What incentives did Transource Missouri request from FERC in formulation of its ATRR?

A. According to the direct testimony of Darrin R. Ives in File No. EO-2012-0367, page 15, Transource Missouri requested the following incentives:

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

Q. What specific differences did KCPL assume between the FERC authorized ratemaking and the modified FERC authorized ratemaking pursuant to the Commission's Report and Order in File No. EA-2013-0098?

A. KCPL identified the following differences related to FERC incentives:

- Return on Equity– FERC authorized Transource Missouri ROE, with risk adder for the Sibley-Nebraska City Project versus Commission ordered ROE.
- Pre-commercial Costs – defer and amortize pre-commercial costs prior to projects becoming in-service versus capitalization of pre-commercial costs.
- CWIP in Rate Base – inclusion of CWIP in rate base versus capitalization of Allowance for Funds Used During Construction ("AFUDC")

- Capital Structure – use of hypothetical 60/40% equity/debt capital structure versus Commission ordered capital structure

KCPL also identified the following difference that is not related to FERC incentives, but is a difference between the Transource Missouri ATRR and Commission ratemaking:

- Cost of Debt – Transource Missouri long-term debt rate versus Commission ordered long term debt rate

Q. Does Staff agree with KCPL's calculations for this adjustment?

A. Not in their entirety. To the extent the ATRR differences related to FERC incentives are captured pursuant to the Commission's Report and Order in File No. EA-2013-0098, the calculations are reasonable. The incentive differences for increased ROE, deferral of pre-commercial costs, CWIP in rate base, and hypothetical capital structure are FERC incentives that represent differences to be captured by this adjustment. The remainder of the differences captured in KCPL's adjustment is not related to FERC incentives and is therefore not contemplated in the adjustment ordered by the Commission in File No. EA-2013-0098. While there are differences between FERC and Commission ratemaking treatment, the Commission's Report and Order did not address these differences, and they should not be considered differences for purposes of calculating of this adjustment.

Q. What are the differences between KCPL's and Staff's calculation of the adjustment?

A. For the ATRR differences identified by KCPL that are not FERC incentives, Staff made those factors equal between Transource Missouri and the hypothetical Missouri ATRR. Specifically, Staff set the rate of long term debt equal between the two calculations.

Q. Does that conclude your rebuttal testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light	)	
Company's Request for Authority to	)	Case No. ER-2016-0285
Implement A General Rate Increase for	)	
Electric Service	)	

AFFIDAVIT OF KEITH MAJORS

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF JACKSON	)	

COMES NOW KEITH MAJORS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Rebuttal; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Keith Majors

KEITH MAJORS

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Jackson, State of Missouri, at my office in Kansas City, on this 29th day of December, 2016.

Tammy Morales

Notary Public

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

TAMMY MORALES
My Commission Expires
January 7, 2018
Clay County
Commission #14451086

SCHEDULE KM-R1

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY.

Missouri Public Service Commission

Respond Data Request

Data Request No.	0228
Company Name	KCP&L Greater Missouri Operations Company-Investor (Electric)
Case/Tracking No.	ER-2016-0156
Date Requested	4/1/2016
Issue	General Information & Miscellaneous - Company Information
Requested From	Lois J Liechti
Requested By	Nathan Williams
Brief Description	GMO monthly surveillance reporting – Crossroads disallowances
Description	1a). Do the KCP&L Greater Missouri Operations surveillance reports (including, but not limited to, FAC Quarterly Surveillance Reports) submitted to the Commission include costs disallowed by the Commission relating to Crossroads, costs such as disallowed depreciation expenses, transmission expenses, etc.? b.) If the disallowed costs are included in the surveillance reports provided to the Commission, please re-calculate each monthly surveillance report submitted to the Commission since the Commission disallowed these Crossroads costs in GMO's 2010 rate case—ER-2010-0356 and 2012 rate case- ER-2012-0175 to most current available, removing the disallowed Crossroads costs for each months' operating results. 2. Identify the amount of disallowed Crossroads costs each month since the effective date of rates in GMO's 2010 rate case—June 2011 to the most current available. Provide monthly updated information as available. DR by Cary Featherstone (cary.featherstone@psc.mo.gov)
Response	Please see the attached.
Objections	NA

The attached information provided to **Missouri Public Service Commission** Staff in response to the above data information request is accurate and complete, and contains no material misrepresentations or omissions, based upon present facts of which the undersigned has knowledge, information or belief. The undersigned agrees to immediately inform the **Missouri Public Service Commission** if, during the pendency of Case No. **ER-2016-0156** before the Commission, any matters are discovered which would materially affect the accuracy or completeness of the attached information. If these data are voluminous, please (1) identify the relevant documents and their location (2) make arrangements with requestor to have documents available for inspection in the **KCP&L Greater Missouri Operations Company-Investor(Electric)** office, or other location mutually agreeable. Where identification of a document is requested, briefly describe the document (e.g. book, letter, memorandum, report) and state the following information as applicable for the particular document: name, title number, author, date of publication and publisher, addresses, date written, and the name and address of the person(s) having possession of the document. As used in this data request the term "document(s)" includes publication of any format, workpapers, letters, memoranda, notes, reports, analyses, computer analyses, test results, studies or data, recordings, transcriptions and printed, typed or written materials of every kind in your possession, custody or control or within your knowledge. The pronoun "you" or "your" refers to **KCP&L Greater Missouri Operations Company-Investor(Electric)** and its employees, contractors, agents or others employed by or acting in its behalf.

Security :	Public
Rationale :	NA

KCPL GMO
Case Name: 2016 GMO Rate Case
Case Number: ER-2016-0156

Response to Featherstone Cary Interrogatories - MPSC_20160401
Date of Response: 6/28/2016

Question:0228R

1a). Do the KCP&L Greater Missouri Operations surveillance reports (including, but not limited to, FAC Quarterly Surveillance Reports) submitted to the Commission include costs disallowed by the Commission relating to Crossroads, costs such as disallowed depreciation expenses, transmission expenses, etc.? b.) If the disallowed costs are included in the surveillance reports provided to the Commission, please re-calculate each monthly surveillance report submitted to the Commission since the Commission disallowed these Crossroads costs in GMO's 2010 rate case—ER-2010-0356 and 2012 rate case- ER-2012-0175 to most current available, removing the disallowed Crossroads costs for each months' operating results. 2. Identify the amount of disallowed Crossroads costs each month since the effective date of rates in GMO's 2010 rate case—June 2011 to the most current available. Provide monthly updated information as available. DR by Cary Featherstone (cary.featherstone@psc.mo.gov)

Response:

1a.) All costs related to Crossroads are included in the GMO surveillance reports submitted on a monthly basis.
1b.) No report currently exists that can re-calculate the effect of removing the Crossroads disallowed costs.

2.) See attached file "Q228R Crossroads Disallowed" for the disallowed Crossroads plant, estimated disallowed Crossroads Accumulated Depreciation Reserve and estimated monthly disallowed depreciation expense. The Crossroads accumulated reserve for the months between the 2010 rate case and the 2012 rate case have not been estimated. An estimated reserve was calculated beginning with the 2012 rate case in order to approximate an estimated reserve for the 2016 rate case. The level of transmission expense disallowed in the prior case was $4,915,609.

Response by:
Amy Murray, Regulatory Accounting

Attachment:
Q0228R_CrossRoads Disallowed.xlsx
Q0228R_Verification.pdf

Disallowed Crossroads
ER-2016-0156
CURB- DR 0228

Case No. ER-2010-0356

FERC Account	Account Description	Per PowerPlant Property Rpts & Calculate PP 12/31/2010	Tot Comp Allowed Gross Plant	Disallowed Gross Plant	Accumulated Reserve Per PowerPlant 12/31/2010	Tot Comp Allowed Accumulated Reserve	Disallowed Accum Reserve	Depr Rate	Est Monthly Amortiz
303.010	Miscellaneous Intangibles - Transmission	21,901,183	$ 9,584,651	$ 12,316,532	4,395,612	$ 579,073	$ 3,816,539	2.50%	$ 25,659
340.000	Other Production - Land	427,390	187,039	240,351	0	$ -	-	0.00%	0
341.000	Other Production - Structures	2,276,012	996,055	1,279,957	285,510	$ 42,125	243,385	1.75%	1,867
342.000	Other Production - Fuel Holders	4,300,000	1,881,816	2,418,184	949,341	$ 140,525	808,816	3.09%	6,227
343.000	Other Production - Prime Movers	80,541,888	35,247,679	45,294,209	23,300,490	$ 4,097,249	19,203,241	4.81%	181,554
344.000	Other Production - Generators	16,595,058	7,262,523	9,332,535	4,418,095	$ 666,942	3,751,153	3.80%	29,553
345.000	Other Production - Accessory Electric Equip.	14,960,000	6,546,969	8,413,031	3,149,467	$ 450,923	2,698,544	2.85%	19,981
346.000	Other Production -Miscellaneous Power Plant	130,859	57,268	73,591	32,076	$ 4,941	27,135	3.57%	219
Total		$ 141,132,390	$ 61,764,000	$ 79,368,390	$ 36,530,591	$ 5,981,778	$ 30,548,813		$265,060

Case No. ER-2012-0175

FERC Account	Account Description	Per PowerPlant Property Rpts & Calculate PP 8/31/2012	Tot Comp Allowed Gross Plant	Disallowed Gross Plant	Accumulated Reserve Per PowerPlant 8/31/2012	Tot Comp Allowed Accumulated Reserve	Disallowed Accum Reserve	Depr Rate	Est Monthly Amortiz
303.010	Miscellaneous Intangibles - Transmission	13,476,338	$ 9,584,651	$ 3,891,687	3,252,183	$ 978,433	$ 2,273,750	2.50%	$ 8,108
340.000	Other Production - Land	427,390	187,039	240,351	0	$ -	-	0.00%	0
341.000	Other Production - Structures	2,395,896	1,115,939	1,279,957	354,691	$ 74,149	280,542	1.75%	1,867
342.000	Other Production - Fuel Holders	4,321,888	1,903,704	2,418,184	1,171,693	$ 238,396	933,297	3.09%	6,227
343.000	Other Production - Prime Movers	80,036,540	35,275,138	44,761,402	29,576,160	$ 6,925,205	22,650,955	4.81%	179,419
344.000	Other Production - Generators	16,932,185	7,994,708	8,937,477	5,456,502	$ 1,088,935	4,367,567	3.80%	28,302
345.000	Other Production - Accessory Electric Equip.	15,557,840	6,805,604	8,752,236	3,865,217	$ 770,391	3,094,826	2.85%	20,787
346.000	Other Production -Miscellaneous Power Plant	130,859	57,268	73,591	39,862	$ 8,348	31,514	3.57%	219
Total		$ 133,278,936	$ 62,924,051	$ 70,354,885	$ 43,716,308	$ 10,083,857	$ 33,632,451		$244,927

Mth Ending	Disallowed Plant	Estimated Disallowed Reserve	
Dec 2011	$ 79,368,390	$ **30,548,813**	**Case No. ER-2010-0356**
Aug 2012	$ 70,354,885	$ **33,632,451**	**Case No. ER-2012-0175**
Sept 2012	70,354,885	33,877,378	
Oct 2012	70,354,885	34,122,305	
Nov 2012	70,354,885	34,367,233	
Dec 2012	70,354,885	34,612,160	
Jan 2013	70,354,885	34,857,087	
Feb 2013	70,354,885	35,102,014	
Mar 2013	70,354,885	35,346,942	
Apr 2013	70,354,885	35,591,869	
May 2013	70,354,885	35,836,796	
Jun 2013	70,354,885	36,081,723	
Jul 2013	70,354,885	36,326,651	
Aug 2013	70,354,885	36,571,578	
Sept 2013	70,354,885	36,816,505	
Oct 2013	70,354,885	37,061,432	
Nov 2013	70,354,885	37,306,359	
Dec 2013	70,354,885	37,551,287	

Jan 2014	70,354,885	37,796,214	
Feb 2014	70,354,885	38,041,141	
Mar 2014	70,354,885	38,286,068	
Apr 2014	70,354,885	38,530,996	
May 2014	70,354,885	38,775,923	
Jun 2014	70,354,885	39,020,850	
Jul 2014	70,354,885	39,265,777	
Aug 2014	70,354,885	39,510,705	
Sept 2014	70,354,885	39,755,632	
Oct 2014	70,354,885	40,000,559	
Nov 2014	70,354,885	40,245,486	
Dec 2014	70,354,885	40,490,414	
Jan 2015	70,354,885	40,735,341	
Feb 2015	70,354,885	40,980,268	
Mar 2015	70,354,885	41,225,195	
Apr 2015	70,354,885	41,470,122	
May 2015	70,354,885	41,715,050	
Jun 2015	70,354,885	**41,959,977**	
Jul 2015	70,354,885	42,204,904	
Aug 2015	70,354,885	42,449,831	
Sept 2015	70,354,885	42,694,759	
Oct 2015	70,354,885	42,939,686	
Nov 2015	70,354,885	43,184,613	
Dec 2015	70,354,885	**43,429,540**	**Dec 2015 Cut-off**
Jan 2016	70,354,885	43,674,468	
Feb 2016	70,354,885	43,919,395	
Mar 2016	70,354,885	44,164,322	
Apr 2016	70,354,885	44,409,249	
May 2016	70,354,885	44,654,176	
Jun 2016	70,354,885	44,899,104	
Jul 2016	70,354,885	**45,144,031**	**July 2016 True-up**

Verification of Response

Kansas City Power & Light Company
AND
KCP&L Greater Missouri Operations

Docket No. ER-2016-0156

The response to Data Request # 0228R is true and accurate to the best of my knowledge and belief.

Signed: Tim Rush

Date: June 28, 2016

SCHEDULE KM-R3

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY.

SCHEDULE KM-R4

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY.

KCPL
Case Name: 2016 KCPL Rate Case
Case Number: ER-2016-0285

Response to Woodsmall David Interrogatories - MECG_20160803
Date of Response: 8/22/2016

Question:3/5/2016

[Cost of Debt].

Has the Company been able to refinance any of its long-term debt, either at maturity or prior to scheduled maturity, at a net savings in interest costs during any of the past five years? Are there expected to be future opportunities, given the structure and tenor of the Company's outstanding long term debt, to reduce debt borrowing costs if financial market conditions remain favorable? Please explain and quantify the annualized net interest cost savings associated with each historical or reasonably anticipated future debt cost savings opportunity identified in your response.

Response:
Yes, KCP&L has been able to refinance some of its long-term debt at a net savings over the past five years. The $150 million 2001 6.5% Senior Notes matured on November 15, 2011 and were refinanced with the $400 million 2011 5.3% Senior Notes that mature on October 1, 2041. KCP&L also has several series of tax-exempt bonds which can be in a long-term interest rate mode for a specific period of time until a mandatory put back to the Company or in a long-term interest rate mode until final maturity or in a floating interest rate mode. Sometimes when a tax-exempt bond is put back to the Company, KCP&L holds the bonds for a while before it remarkets the bonds to new investors. All of the currently outstanding tax-exempt bonds have had changes in interest rates over the past five years. On June 30, 2011, the $265.938 million of outstanding tax-exempt bonds had a weighted average cost of 5.16% and on June 30, 2016, the $280.38 million of outstanding tax-exempt bonds had a weighted average cost of 1.86%.

Yes, there are expected to be future opportunities to reduce debt borrowing costs. KCP&L has taxable long-term debt maturing in 2017, 2018 and 2019 that it expects to refinance at lower cost when it matures. The $250 million 2007 5.85% Senior Notes mature on June 15, 2017. The $350 million 2008 6.375% Senior Notes mature on March 1, 2018. The $400 million 2009 7.15% Mortgage Bonds mature on April 1, 2019. Recent indicative new issue pricing for 10 year debt is around 2.86% and for 30 year debt it is around 3.83%. KCP&L also has a $31 million 1.25% tax-exempt bond that matures July 1, 2017 which it does not expect to refinance at a lower cost and is expected to be refinanced by combining it with the 2017 Senior Note maturity. The maturing long-term debt in 2017 through 2019 is expected to be refinanced with some 10 year and some 30 year debt depending on market conditions.

Historical annual savings:

Senior notes = $150 million * (6.5%-5.3%) = $1.8 million
Tax exempt bonds= $265.938 million * (5.16%-1.86%) = $8.776 million

Future potential annual savings based on current 10 year indicative rates:
2007 Senior note = $250 million * (5.85%-2.86%) = $7.475 million
2008 Senior note = $350 million * (6.375%-2.86%) = $12.3 million
2009 Mortgage bonds = $400 million * (7.15%-2.86%) = $17.16 million

Future potential annual savings based on current 30 year indicative rates:
2007 Senior note = $250 million * (5.85%-3.83%) = $5.05 million
2008 Senior note = $350 million * (6.375%-3.83%) = $8.9 million
2009 Mortgage bonds = $400 million * (7.15%-3.83%) = $13.28 million

Information provided by Gregg Clizer

Attachment: Q3-5_Verification.pdf

KCPL
Case No. ER-2016-0285
Surveillance Return on Equity - Source - Filed Surveillance Reports
KCPL Income, Beginning and Ending Equity - Source - SEC 10-K Filings
EEI Average ROE - Source - EEI Rate Case Summary, Q4 2015

Year	KCPL Income Available for Common Stockholders	KCPL Beginning Common Stock Equity	KCPL Ending Common Stock Equity	KCPL Return on Equity, Avg. Balance	KCPL MO Jurisdictional ROE	EEI - Average Electric Utility Authorized ROE	KCPL MO Authorized ROE
1993	102,619,000	853,924,000	866,151,000	11.93%	12.30%	11.42%	15.00%
1994	101,318,000	866,151,000	874,699,000	11.64%	11.67%	11.55%	15.00%
1995	118,575,000	874,699,000	897,938,000	13.38%	NA	11.56%	15.00%
1996	104,381,000	897,938,000	910,449,000	11.54%	NA	11.31%	15.00%
1997	72,771,000	910,449,000	878,420,000	8.14%	12.90%	11.44%	15.00%
1998	116,838,000	878,420,000	891,802,000	13.20%	14.13%	11.87%	15.00%
1999	78,182,000	891,802,000	864,644,000	8.90%	10.07%	10.80%	15.00%
2000	157,055,000	864,644,000	921,352,000	17.59%	8.26%	11.57%	15.00%
2001	118,593,000	921,352,000	744,383,000	14.24%	11.17%	11.15%	15.00%
2002	95,699,000	744,383,000	745,033,000	12.85%	13.55%	11.07%	15.00%
2003	117,155,000	745,033,000	855,558,000	14.64%	12.20%	10.92%	15.00%
2004	145,028,000	855,558,000	1,110,243,000	14.76%	11.57%	10.83%	15.00%
2005	143,645,000	1,110,243,000	1,151,613,000	12.70%	10.3%, revised for 4 CP Demand	10.52%	15.00%
2006	149,321,000	1,151,613,000	1,383,143,000	11.78%	8.6%, revised for allocations	10.30%	15.00%
2007	156,700,000	1,383,143,000	1,479,400,000	10.95%	10.04%	10.26%	11.25%
2008	125,200,000	1,479,400,000	1,621,900,000	8.07%	7.69%	10.34%	10.75%
2009	128,900,000	1,621,900,000	1,931,700,000	7.25%	6.15%	10.47%	10.75%
2010	163,200,000	1,931,700,000	2,005,000,000	8.29%	6.91%	10.29%	Settlement
2011	135,500,000	2,005,000,000	2,045,500,000	6.69%	5.09%	10.25%	10.00%
2012	141,600,000	2,045,500,000	2,096,700,000	6.84%	5.84%	10.15%	10.00%
2013	169,000,000	2,096,700,000	2,179,300,000	7.90%	6.49%	9.99%	9.70%
2014	162,400,000	2,179,300,000	2,275,000,000	7.29%	5.69%	9.93%	9.70%
2015	152,800,000	2,275,000,000	2,443,100,000	6.48%	5.25%	9.78%	9.70%

Edison Electric INSTITUTE

Rate Case Summary

Q4 2015
FINANCIAL UPDATE

QUARTERLY REPORT
OF THE U.S. SHAREHOLDER-OWNED
ELECTRIC UTILITY INDUSTRY

About EEI

The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for 220 million Americans, operate in all 50 states and the District of Columbia, and directly employ more than 500,000 workers. With $100 billion in annual capital expenditures, the electric power industry is responsible for millions of additional jobs. Reliable, affordable, and sustainable electricity powers the economy and enhances the lives of all Americans. EEI has 70 international electric companies as Affiliate Members, and 270 industry suppliers and related organizations as Associate Members. Organized in 1933, EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

About EEI's Quarterly Financial Updates

EEI's quarterly financial updates present industry trend analyses and financial data covering 52 U.S. shareholder-owned electric utility companies. These 52 companies include 47 electric utility holding companies whose stocks are traded on major U.S. stock exchanges and five electric utilities who are subsidiaries of non-utility or foreign companies. Financial updates are published for the following topics:

Dividends	Rate Case Summary
Stock Performance	SEC Financial Statements (Holding Companies)
Credit Ratings	FERC Financial Statements (Regulated Utilities)
Construction	Fuel

EEI Finance Department material can be found online at: www.eei.org/QFU

For EEI Member Companies

The EEI Finance and Accounting Division is developing current year and historical data sets that cover a wide range of industry financial and operating metrics. We look forward to serving as a resource for member companies who wish to produce customized industry financial data and trend analyses for use in:

- Investor relations studies and presentations
- Internal company presentations
- Performance benchmarking
- Peer group analyses
- Annual and quarterly reports to shareholders

We Welcome Your Feedback

EEI is interested in ensuring that our financial publications and industry data sets best address the needs of member companies and the financial community. We welcome your comments, suggestions and inquiries.

Contact:
Mark Agnew
Director, Financial Analysis
(202) 508-5049, magnew@eei.org

Bill Pfister
Manager, Financial Analysis
(202) 508-5531, bpfister@eei.org

Michael Buckley
Financial Analyst
(202) 508-5614, mbuckley@eei.org

Future EEI Finance Meetings

EEI Wall Street Briefing
February 10, 2016
University Club
New York, New York

EEI Financial Conference
November 6-9, 2016
JW Marriott Desert Ridge Resort & Spa
Phoenix, Arizona

For more information about EEI Finance Meetings, please contact Debra Henry, (202) 508-5496, dhenry@eei.org

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

The 52 U.S. Shareholder-Owned Electric Utilities

The companies listed below all serve a regulated distribution territory. Other utilities, such as transmission provider ITC Holdings, are not shown below because they do not serve a regulated distribution territory. However, their financial information is included in relevant EEI data sets, such as transmission-related construction spending.

ALLETE, Inc. (ALE)
Alliant Energy Corporation (LNT)
Ameren Corporation (AEE)
American Electric Power Company, Inc. (AEP)
AVANGRID, Inc. (AGR)
Avista Corporation (AVA)
Berkshire Hathaway Energy
Black Hills Corporation (BKH)
CenterPoint Energy, Inc. (CNP)
Cleco Corporation (CNL)
CMS Energy Corporation (CMS)
Consolidated Edison, Inc. (ED)
Dominion Resources, Inc. (D)
DPL, Inc.
DTE Energy Company (DTE)
Duke Energy Corporation (DUK)
Edison International (EIX)
El Paso Electric Company (EE)
Empire District Electric Company (EDE)
Energy Future Holdings Corp. (formerly TXU Corp.)
Entergy Corporation (ETR)
Eversource Energy (ES)
Exelon Corporation (EXC)
FirstEnergy Corp. (FE)
Great Plains Energy Incorporated (GXP)
Hawaiian Electric Industries, Inc. (HE)
IDACORP, Inc. (IDA)
IPALCO Enterprises, Inc.
MDU Resources Group, Inc. (MDU)
MGE Energy, Inc. (MGEE)
NextEra Energy, Inc. (NEE)
NiSource Inc. (NI)
NorthWestern Corporation (NWE)
OGE Energy Corp. (OGE)
Otter Tail Corporation (OTTR)
Pepco Holdings, Inc. (POM)
PG&E Corporation (PCG)
Pinnacle West Capital Corporation (PNW)
PNM Resources, Inc. (PNM)
Portland General Electric Company (POR)
PPL Corporation (PPL)
Public Service Enterprise Group Inc. (PEG)
Puget Energy, Inc.
SCANA Corporation (SCG)
Sempra Energy (SRE)
Southern Company (SO)
TECO Energy, Inc. (TE)
Unitil Corporation (UTL)
Vectren Corporation (VVC)
WEC Energy Group, Inc. (WEC)
Westar Energy, Inc. (WR)
Xcel Energy, Inc. (XEL)

Companies Listed by Category
(as of 12/31/2015)

Please refer to the Quarterly Financial Updates webpage for previous years' lists.

Given the diversity of utility holding company corporate strategies, no single company categorization approach will be useful for all EEI members and utility industry analysts. Never-the-less, we believe the following classification provides an informative framework for tracking financial trends and the capital markets' response to business strategies as companies depart from the traditional regulated utility model.

Regulated	80%+ of total assets are regulated
Mostly Regulated	50% to 80% of total assets are regulated
Diversified	Less than 50% of total assets are regulated

Categorization of the 47 publicly traded utility holding companies is based on year-end business segmentation data presented in 10Ks, supplemented by discussions with company IR departments. Categorization of the five non-publicly traded companies (*shown in italics*) is based on estimates derived from FERC Form 1 data and information provided by parent company IR departments.

The EEI Finance and Accounting Division continues to evaluate our approach to company categorization and business segmentation. In addition, we can produce customized categorization and peer group analyses in response to member company requests. We welcome comments, suggestions and feedback from EEI member companies and the financial community.

Regulated (36 of 52)

ALLETE, Inc.
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company, Inc.
AVANGRID, Inc.
Avista Corporation
Black Hills Corporation
Cleco Corporation
CMS Energy Corporation
Consolidated Edison, Inc.
DPL, Inc.
DTE Energy Company
Duke Energy Corporation
Edison International
El Paso Electric Company
Empire District Electric Company
Entergy Corporation
Eversource Energy
Great Plains Energy Incorporated
IDACORP, Inc.
IPALCO Enterprises, Inc.
NorthWestern Energy
OGE Energy Corp.
Otter Tail Corporation
Pepco Holdings, Inc.
PG&E Corporation
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
Puget Energy, Inc.
Southern Company
TECO Energy, Inc.
Unitil Corporation
Westar Energy, Inc.
WEC Energy Group, Inc.
Xcel Energy, Inc.

Mostly Regulated (13 of 52)

Berkshire Hathaway Energy
CenterPoint Energy, Inc.
Dominion Resources, Inc.
Exelon Corporation
FirstEnergy Corp.
MGE Energy, Inc.
NextEra Energy, Inc.
NiSource Inc.
PPL Corporation
Public Service Enterprise Group, Inc.
SCANA Corporation
Sempra Energy
Vectren Corporation

Diversified (3 of 52)

Energy Future Holdings
Hawaiian Electric Industries, Inc.
MDU Resources Group, Inc.

Note: Based on assets at 12/31/2014

Q4 2015

Rate Case Summary

HIGHLIGHTS

- Investor-owned electric utilities filed 11 new rate cases in Q4 while 20 cases were decided. The combined total indicates rate case activity continues at a heightened level.
- The average awarded ROE in Q4 was 9.62%, a near-record low in our over-three-decades of data. During Q3, two commissions noted the significant decline in capital market costs when rejecting higher requested ROEs.
- An emerging trend in the electric utility industry is the attempt by companies to introduce three-part rates for residential customers. Three-part rates better capture the nature of costs utilities incur to serve customers and can help diminish cost shifting between customers, particularly when usage patterns vary dramatically (as is increasingly the case with growing use of rooftop solar and battery storage).

COMMENTARY

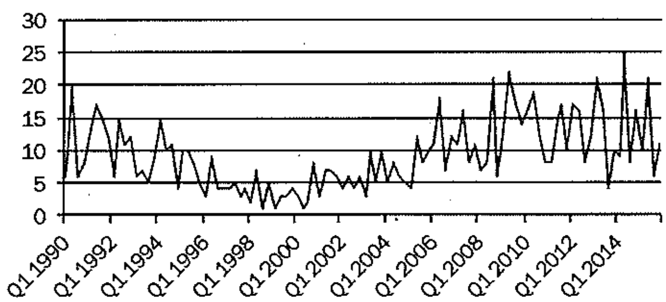
Investor-owned electric utilities filed 11 new rate cases in Q4 2015 while decisions were reached in 20 cases; the combined total indicates that regulatory activity in the industry continues at a heightened level. The average awarded ROE for Q4 was 9.62%, the second lowest in our more than three decades of historical data and consistent with the declining trend during the period. The average requested ROE in Q4, at 10.33%, was also near the minimum in our dataset and consistent with a similar continuous downward trend. Regulatory lag in Q4, at 9.44 months, was near the long-term average lag of about 10 months.

Filed Cases in Q4

As is typical in the industry, electric utilities' need to recover for capital expenditures was the primary reason for Q4 filings. Empire District in Missouri filed in part to convert a generating plant to a combined-cycle unit. Baltimore Gas filed in part to recover for investments in Smart Grid and safety/system reliability investments. Smart Grid investments accounted for $137.1 million of the company's requested

I. Number of Rate Cases Filed (Quarterly)

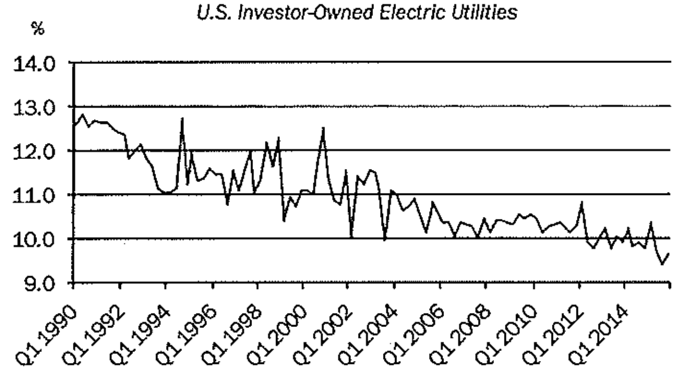
U.S. Investor-Owned Electric Utilities



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

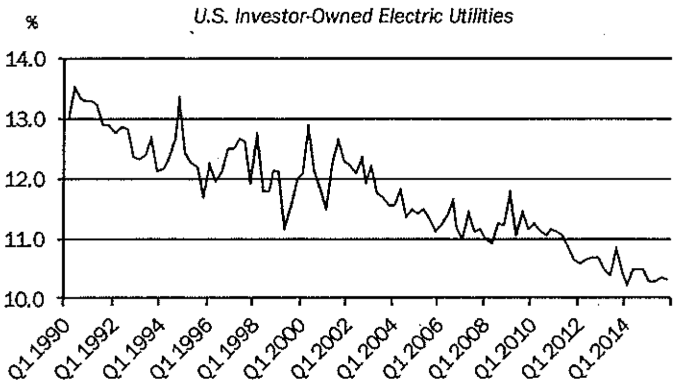
II. Average Awarded ROE (Quarterly)

U.S. Investor-Owned Electric Utilities



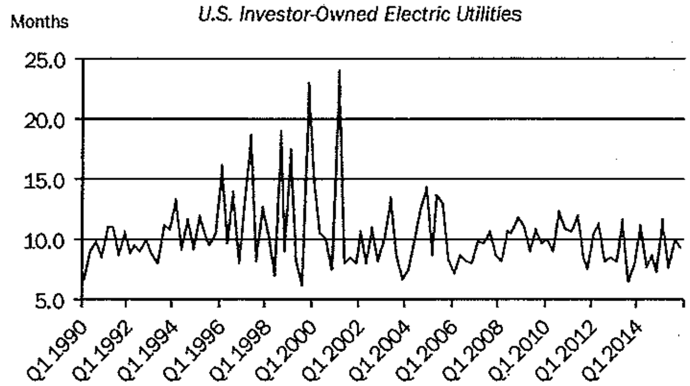
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

III. Average Requested ROE (Quarterly)



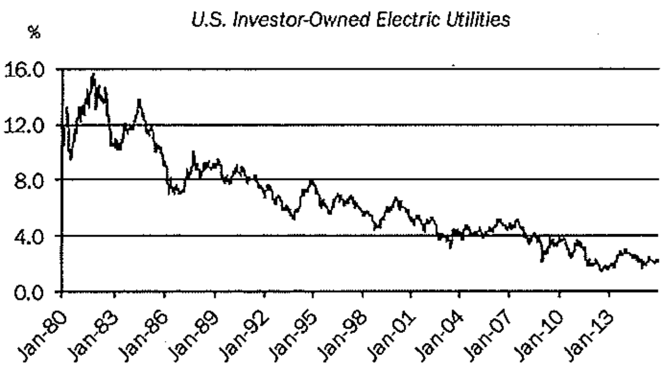
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

IV. Average Regulatory Lag (Quarterly)



Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

V. 10-Year Treasury Yield (1/1980—12/2015)



Source: U.S. Federal Reserve

$213 million (electric and gas) increase. PacifiCorp in Washington state filed in part to recover emission control investments at a coal plant.

Utility interest in implementing or modifying rate mechanisms, such as trackers, is often a primary driver of rate filings; this was true in Q4. Massachusetts Electric filed in part to increase the cap on its capital investment recovery mechanism from $170 million to $285 million and would like to implement a property tax tracker mechanism. Baltimore Gas and Electric would like to implement a tracker mechanism to recover increased costs associated with using Baltimore's underground conduit system. PacifiCorp in Washington filed in part to implement a revenue decoupling mechanism; if the mechanism is approved, the company indicated it would not need to file another case asking for an increase until 4/1/2018.

An additional driver of filings in Q4 was the desire to increase customer charges. Empire District in Missouri filed in part to increase its residential customer charge from $12.52 to $14.47 and its commercial customer charge from $22 to $23.47. Northern Indiana Public Service would like to increase its residential customer charge from $11 to $20.

An emerging trend in the electric utility industry (and other utility industries as well) is the attempt by companies to introduce three-part rates for residential customers. The three components of such rates are a fixed customer charge, a variable demand charge, and a volumetric usage charge. Three-part rates have been common for commercial and industrial customers for many years, but such a rate design for residential customers is uncommon. Three-part rates better capture the nature of costs utilities incur to serve customers and can help diminish cost shifting between customers, particularly when usage patterns vary dramatically (as is increasingly the case with growing use of rooftop solar and battery storage). Oklahoma Gas and Electric filed in Q4 to implement a three-part rate for residential customers. Under this new rate structure, the customer charge increases from $13 to $26.54, the demand charge is $2.75 per kilowatt, and the usage charge is reduced commensurately.

Miscellaneous

Tucson Electric Power filed in part to recover for declining use per customer and lower overall sales; the company would also like to implement economic development rates. PacifiCorp in Washington is asking for expedited treatment in its case since it meets the related requirements; these specify that the filing asks for: 1) less than a 3% increase in gross annual revenues, 2) an increase in gross revenues of no more than 3% from any class of service, and 3) no change in the allowed ROE or capital structure. Dayton Power and Light is filing its first base rate case in 24 years. In its filing, Oklahoma Gas and Electric said it terminated its supply agreements to free up power to serve its native customers at low prices.

Decided Cases in Q4

ROE and Capital Structure

Orange & Rockland's joint proposal (JP) that was approved by the New York commission authorized a 9% ROE and a 48% equity share of the capital structure. The commission found this consistent with other major utilities operating under multi-year rate plans, saying "this level of equity adequately balances the need to maintain a utility's financial strength with the revenue requirement impact of relatively

VI. Rate Case Data: From Tables I-V

U.S. Investor-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q4 1988	1	NA	14.30	8.96	NA
Q1 1989	4	NA	15.26	9.21	NA
Q2 1989	4	NA	13.30	8.77	NA
Q3 1989	14	NA	13.65	8.11	NA
Q4 1989	13	NA	13.47	7.91	NA
Q1 1990	6	12.62	13.00	8.42	6.71
Q2 1990	20	12.85	13.51	8.68	9.07
Q3 1990	6	12.54	13.34	8.70	9.90
Q4 1990	8	12.68	13.31	8.40	8.61
Q1 1991	13	12.66	13.29	8.02	11.00
Q2 1991	17	12.67	13.23	8.13	11.00
Q3 1991	15	12.49	12.89	7.94	8.70
Q4 1991	12	12.42	12.90	7.35	10.70
Q1 1992	6	12.38	12.77	7.30	8.90
Q2 1992	15	11.83	12.86	7.38	9.61
Q3 1992	11	12.03	12.81	6.62	9.00
Q4 1992	12	12.14	12.36	6.74	10.10
Q1 1993	6	11.84	12.33	6.28	8.87
Q2 1993	7	11.64	12.39	5.99	8.10
Q3 1993	5	11.15	12.70	5.62	11.20
Q4 1993	9	11.04	12.12	5.61	10.90
Q1 1994	15	11.07	12.15	6.07	13.40
Q2 1994	10	11.13	12.37	7.08	9.28
Q3 1994	11	12.75	12.66	7.33	11.80
Q4 1994	4	11.24	13.36	7.84	9.26
Q1 1995	10	11.96	12.44	7.48	12.00
Q2 1995	10	11.32	12.26	6.62	10.40
Q3 1995	8	11.37	12.19	6.32	9.50
Q4 1995	5	11.58	11.69	5.89	10.60
Q1 1996	3	11.46	12.25	5.91	16.30
Q2 1996	9	11.46	11.96	6.72	9.80
Q3 1996	4	10.76	12.13	6.78	14.00
Q4 1996	4	11.56	12.48	6.34	8.12
Q1 1997	4	11.08	12.50	6.56	13.80
Q2 1997	5	11.62	12.66	6.70	18.70
Q3 1997	3	12.00	12.63	6.24	8.33
Q4 1997	4	11.06	11.93	5.91	12.70
Q1 1998	2	11.31	12.75	5.59	10.20
Q2 1998	7	12.20	11.78	5.60	7.00
Q3 1998	1	11.65	NA	5.20	19.00
Q4 1998	5	12.30	12.11	4.67	9.11
Q1 1999	1	10.40	NA	4.98	17.60
Q2 1999	3	10.94	11.17	5.54	8.33
Q3 1999	3	10.75	11.57	5.88	6.33
Q4 1999	4	11.10	12.00	6.14	23.00
Q1 2000	3	11.08	12.10	6.48	15.10
Q2 2000	1	11.00	12.90	6.18	10.50
Q3 2000	2	11.68	12.13	5.89	10.00
Q4 2000	8	12.50	11.81	5.57	7.50
Q1 2001	3	11.38	11.50	5.05	24.00
Q2 2001	7	10.88	12.24	5.27	8.00
Q3 2001	7	10.78	12.64	4.98	8.62
Q4 2001	6	11.57	12.29	4.77	8.00
Q1 2002	4	10.05	12.22	5.08	10.80
Q2 2002	6	11.41	12.08	5.10	8.16
Q3 2002	4	11.25	12.36	4.26	11.00
Q4 2002	6	11.57	11.92	4.01	8.25

VI. Rate Case Data: From Tables I-V (cont.)

U.S. Investor-Owned Electric Utilities

Quarter	Number of Rate Cases Filed	Average Awarded ROE	Average Requested ROE	Average 10-Year Treasury Yield	Average Regulatory Lag
Q1 2003	3	11.49	12.24	3.92	10.20
Q2 2003	10	11.16	11.76	3.62	13.60
Q3 2003	5	9.95	11.69	4.23	8.80
Q4 2003	10	11.09	11.57	4.29	6.83
Q1 2004	5	11.00	11.54	4.02	7.66
Q2 2004	8	10.64	11.81	4.60	10.00
Q3 2004	6	10.75	11.35	4.30	12.50
Q4 2004	5	10.91	11.48	4.17	14.40
Q1 2005	4	10.55	11.41	4.30	8.71
Q2 2005	12	10.13	11.49	4.16	13.70
Q3 2005	8	10.84	11.32	4.21	13.00
Q4 2005	10	10.57	11.14	4.49	8.44
Q1 2006	11	10.38	11.23	4.57	7.33
Q2 2006	18	10.39	11.38	5.07	8.83
Q3 2006	7	10.06	11.64	4.90	8.33
Q4 2006	12	10.38	11.19	4.63	8.11
Q1 2007	11	10.30	11.00	4.68	9.88
Q2 2007	16	10.27	11.44	4.85	9.82
Q3 2007	8	10.02	11.13	4.73	10.80
Q4 2007	11	10.44	11.16	4.26	8.75
Q1 2008	7	10.15	10.98	3.66	7.33
Q2 2008	8	10.41	10.93	3.89	10.80
Q3 2008	21	10.42	11.26	3.86	10.60
Q4 2008	6	10.38	11.21	3.25	11.90
Q1 2009	13	10.31	11.79	2.74	11.10
Q2 2009	22	10.55	11.01	3.31	9.13
Q3 2009	17	10.46	11.43	3.52	10.90
Q4 2009	14	10.54	11.15	3.46	9.69
Q1 2010	16	10.45	11.24	3.72	10.00
Q2 2010	19	10.12	11.12	3.49	9.00
Q3 2010	12	10.27	11.07	2.79	12.40
Q4 2010	8	10.30	11.17	2.86	10.90
Q1 2011	8	10.35	11.11	3.46	10.80
Q2 2011	15	10.24	11.06	3.21	12.00
Q3 2011	17	10.13	10.86	2.43	8.64
Q4 2011	10	10.29	10.66	2.05	7.60
Q1 2012	17	10.84	10.57	2.04	10.50
Q2 2012	16	9.92	10.66	1.82	11.40
Q3 2012	8	9.78	10.68	1.64	8.20
Q4 2012	12	10.05	10.69	1.71	8.65
Q1 2013	21	10.23	10.48	1.95	8.24
Q2 2013	16	9.77	10.40	2.00	11.80
Q3 2013	4	10.06	10.85	2.71	6.55
Q4 2013	10	9.90	10.46	2.75	8.14
Q1 2014	9	10.23	10.22	2.76	11.30
Q2 2014	25	9.83	10.48	2.62	7.83
Q3 2014	8	9.89	10.48	2.50	8.67
Q4 2014	16	9.78	10.47	2.28	7.42
Q1 2015	10	10.37	10.29	2.17	11.80
Q2 2015	21	9.73	10.30	2.17	7.74
Q3 2015	6	9.40	10.35	2.22	10.00
Q4 2015	11	9.62	10.33	2.19	9.44

NA = Not available
Source: SNL Financial / Regulatory Research Assoc. and EEI Rate Department

expensive equity capital." Staff had recommended an 8.5% ROE and the commission said that it has "been very consistent in past years in adopting ROEs in JPs based on the expectation that, in any fully litigated case, the ROE would very likely hew closely to the level recommended in Staff's testimony." In this case, the commission found that the larger ROE "is appropriate in the context of an agreement that provides customers with numerous other material benefits. One of the benefits is a multi-year rate plan, where the company takes on additional financial and business risks by agreeing not to reset the rate of return or many cost elements. These additional risks are usually recognized by adding a stay-out premium to the ROE."

In Consumers Energy's case in Michigan, the commission authorized a 10.3% ROE, which is 0.4% less than the company requested, but 0.3% more than the administrative law judge and some others recommended. The commission said "Consumers has planned an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements. . . . Consumers showed, using Staff's exhibit, that the average ROE resulting from recently decided cases in Michigan, Indiana, Ohio, Pennsylvania, and Wisconsin was 10.26%. The Commission acknowledges that ROEs, nationally, have shown a steady decline (as they have in Michigan), and [notes] that Michigan's economy has stabilized; but finds that, under present circumstances, it is reasonable to assume that investor expectations may be rising." Commissioner Sally A. Talberg (I) dissented, saying an allowed ROE of 10% "is more reasonable based on the record evidence."

In Northern States Power's case in Wisconsin, the company had asked for a 10.2% ROE, the ROE that the commission authorized in the company's previous rate case. The commission authorized a 10% ROE in the Q4 case, finding that "factors such as forward-looking test years, annual rate cases, and higher levels of fixed charges, mitigate some risks and suggest that a lower return is reasonable. The Commission has traditionally made gradual, rather than dramatic, adjustments to the return on equity. . . . [The authorized ROE] reflects all of the financial conditions that affect a utility's cost of equity and as a result, it is not reasonable to identify a specific reduction attributable to any single factor, such as the level of customer charges." Commissioner Huebsch dissented, supporting a 9.75% ROE and saying that the reduction in the authorized ROE "is too small a step in relation to the record from across the industry and across the country. In the interest of ratepayers and in keeping Wisconsin's energy prices competitive, a reduction to 9.75% . . . is incremental in a way to diminish the impact upon the company's ability to attract capital and more closely reflects the current market."

The commission also said that it is responsible for protecting customers from activities that might harm the financial health of the regulated utility, including activities by the parent company that prioritize non-utility needs over those of the utility. This extends to the capital structure and dividend policy of the parent company and to both foreseen and unforeseen capital requirements of the utility. Consequently, the commission ruled that it would be reasonable to restrict the company from paying standard dividends, including pass-through of subsidiary dividends, if the common equity ratio falls below 52.5%.

Customer Charges

In Northern States Power's case in Wisconsin, the commission voted to increase the residential customer charge from \$8 to \$14. The company had requested an increase to \$18, subsequently amended to \$17.25. The commission commented that this case has "a robust record for the Commission to make a decision regarding which functional costs components are appropriate to be considered for recovery through the customer charge. . . . Increasing the customer charge will put [the company] in a better position to accommodate a wide range of customer behavior and to be able to more appropriately respond to the impacts that flow from the increasingly more diverse choices individual customers can, or may in the future, make to manage their energy supply and use. [The company] also considered the increasing number of customers that are expressing more interest in having more choices in their energy supply, along with the increasing number of options available in the market for customers to manage their load. [The company] supports the evolution of the grid, but as more customers choose to generate some or more of their own energy onsite, or invest in options to change how they use energy, the company wants to ensure that other customers, who do not, or cannot, make these investments do not bear a disproportionate share of the costs of providing basic electric service to all customers. Indeed, [the company] proposed its customer charge increase in order to reduce intra-class subsidies. Similarly, under [the company's] proposal, a fundamental price signal remains intact, which is that customers who use more energy will have higher bills, and customers who use less energy will have lower bills. Lastly, increasing the amount of fixed costs [the company] recovers through customer charges instead of through energy charges helps [the company] become less dependent upon customer consumption levels as the basis for cost recovery."

In DTE Electric's case in Michigan, the company had requested an increase in the residential customer charge from \$6 to \$10 and in the commercial customer charge from \$8.78 to \$16. The commission rejected the requests, finding the company's cost of service study flawed, because a number of the costs, while customer-related, are costs that did not vary with the number of customers on the system. The order said, "The Commission has determined that the costs to be included in the customer charge are the marginal costs associated with attaching a customer to the system. . . . the [National Association of Regulatory Utility Commissioners] Manual likewise supports only using the marginal costs of customer attachment in developing the customer charge."

In Southwestern Public Service's case in Texas the company requested an increase in the customer charge from $7.60 to $9.50, which the commission accepted, based on the reasoning of the administrative law judge, who said "The cost of service to the residential class has increased. Therefore the service connection charge for the residential class should also increase. [This will] alleviate some of the inequity of customers with higher load factors that use capacity more efficiently bearing some of the capacity costs caused by residential customers that use the system less efficiently. . . . an argument could be made for increasing the service connection charge to the full, component cost of service, which the preponderance of evidence shows is $11.42 per month. However, given the consideration . . . concerning (a) energy conservation incentives; (b) untoward effects on lower income customers; . . . SWPS's proposal to raise the residential service connectivity charge to $9.50 is an appropriate compromise and should be adopted."

Incentive Compensation

In Consumers Energy's case in Michigan, the commission reduced the company's requested expenses associated with restricted stock compensation and the supplemental executive retirement plan by $12 million, finding "the benefits to ratepayers are not commensurate with the costs" and "the Commission is able to identify few, if any, metrics . . . that are tied to ratepayer benefits." The commission also denied the requested level of long-term incentive compensation proposed by the company, saying the company failed to demonstrate the benefits of the compensation were commensurate with the costs and that "Consumers' long-term incentive compensation is tied closely to company earnings and cash flow measurements that overwhelmingly benefit shareholders."

In Commonwealth Edison's case in Illinois the commission disallowed costs associated with a profit-sharing contribution the company made to its employee savings plan, because the contribution was based on financial metrics, rather than operational metrics. The company had argued that the employee savings plan is an employee benefit, and consequently not financially based incentive compensation, and that the company had included these costs in previous filings without dispute.

In Southwestern Public Service's case in Texas the company said that the financially based incentives had been removed from the incentive compensation part of its filing. However, some intervenors in the case argued that all incentives are financially based and should be disallowed. The Office of Public Utility Counsel recommended a partial reduction to the company's filing for incentive compensation "to better reflect that the plan has a financially-based trigger and incents each employee to meet financially-based performance goals." The commission adopted this partial reduction, saying "SWPS has sufficiently demonstrated that some portion of the plan is tied to performance-based objectives and is part of the necessary expense of attracting and retaining qualified . . . employees. Therefore, removing all the expense of the plan . . . would be improper."

PPL Electric Utilities (Pennsylvania)

PPL Electric Utilities entered into a settlement the commission approved in Q4. The settlement is silent on many rate parameters but disallows a company-requested $14.09 increase to the residential customer charge. The settlement also requires the company to hold a collaborative with all interested parties before 3/1/2016 on the possibility of the company's implementing a revenue decoupling charge. The company is also required to study the legality, feasibility and technical requirements of interconnecting distributed generation storage and battery facilities with its system. Further, the company is to hold a collaborative by 5/1/2016 with all interested stakeholders to discuss the possibility of customers in the assistance program participating in the competitive shopping market. The company is to increase its customer assistance program credits by half of the residential rate increase and its Low Income Usage Reduction Program funding by $0.5 million starting 1/1/2016.

Mississippi Power

In Q4, the Mississippi commission approved a settlement in the Kemper integrated coal gasification combined-cycle plant case. The granted rate increase of $126.1 million reflects only those parts of the plant that are currently in service, including a lignite mine. This order follows the commission's rescission of its previous order adopting rate recognition of the plant, after the Mississippi Supreme Court reversed and remanded the order to the commission. The Southern Mississippi Electric Power Association was to purchase 15% of the plant, but terminated that agreement. The decision also follows the commission's approval of the company's request to implement an interim rate increase. In approving the interim rates, the commission observed that the company was on the "brink of bankruptcy."

Miscellaneous

In Orange & Rockland's case in Q4, the approved Joint Proposal (JP), adhering to New York's statewide Reforming the Energy Vision initiative, adopted a distributed energy resource project intended to defer construction of a new electric substation in Pomona. The JP caps total spending on the project at $9.5 million, and the company can recover $0.4 million per year for the project through base rates. An ROE incentive up to 100 basis points is associated with the project, 50 basis points for achieving targeted cost savings and 50 basis points for achieving load reduction benchmarks.

In Virginia Electric & Power's biennial review case, the commission excluded revenues and costs associated with the company's serving a semi-conductor facility (Micron), finding that facility was not located in "Dominion's exclusive territory established by the Commission. . . . Dominion understandably did not seek the Commission's authority to serve a customer of a municipal utility [Manassas] . . . because the statute does not grant the Commission authority over such a transaction. Under this statutory scheme, Micron has no ability to seek regulatory relief from the Commission . . . Indeed Manassas has not disposed of its right to serve Micron . . . and Micron ultimately remains under the jurisdiction of the municipal electric utility . . . Accordingly, the Commission finds that Micron is not a Virginia jurisdictional customer of Dominion for purposes of the Commission's determination of the utility's earned return . . . This finding increases the Company's biennial review earnings by approximately $5.4 million."

In Commonwealth Edison's case in Illinois, the commission disallowed costs associated with the merger between Exelon (parent of Commonwealth Edison) and Pepco Holdings. The commission found that the merger expenses were prudent and reasonable, but because the District of Columbia commission had not yet approved the merger, savings generated to offset the costs of the merger were not yet likely.

In DTE Electric's case in Michigan, the company proposed a 10.75% ROE. The commission staff and the administrative law judge suggested a 10% ROE. The commission awarded the company a 10.3% ROE, noting that "DTE Electric has an ambitious capital investment program, much of which is related to environmental and generation expenditures that are unavoidable and are saddled with time requirements. . . . Nationally, and in Michigan, ROEs have shown a steady decline, and . . . Michigan's economy has stabilized; . . . economic conditions in DTE's service territory have improved markedly, and access to credit is no longer an issue . . . the Commission finds that the risk associated with DTE Electric has also decreased, and that an ROE of 10.3% appropriately reflects these changes."

In PECO Energy's case in Pennsylvania, an approved settlement determined that new large-volume customers with on-site generation are to be served under the company-proposed pilot Capacity Reservation Rider (CRR). Under the rider, customers pay a reservation fee associated with the potential for them to need access to the distribution system when customer-owned generation is offline. The company's Auxiliary Service Rider serves customers whose generation was online before 1/1/2016. Based on data the company collects before its next rate case, the company may propose to put customers who were online before 1/1/2016 on the CRR. The settlement requires the company to collect data on distribution costs associated with customers taking service at transmission voltage levels or close to a substation, and on usage for all distributed generation on the company's system, and make this data available to the parties to the settlement.■

SNL

Missouri Public Service Commission

General Information	
Contact information	200 Madision Street PO Box 360 Jefferson City, MO 65102-0360 (573) 751-3234 http://www.psc.mo.gov/
No. of Commissioners	5 of 5
Method of Selection	Commissioners: Gubernatorial appointment, Senate confirmation Chairperson: Appointed by and serves at the pleasure of the Governor
Term of Office	Commissioners: 6 years Chairperson: Indefinite
Chairperson	Daniel Hall
Deputy Chairperson	NA
Governor	Jay Nixon (D) – elected in January, 2009
Services Regulated	Electric cooperatives, Electric utilities, Gas utilities, Securities companies, Sewer utilities, Steam utilities, Telecommunications utilities, Water utilities
RRA Ranking	Average/2 (1/8/2008)
Commission Budget	$18 million
Commissioner Salaries	Commissioners: $108,000 Chairperson: $108,000
Size of Staff	205
Rate Cases	Missouri Public Service Commission
Research Notes	RRA Articles
RRA Contact	Russell Ernst

Commissioners

Name	Party	Began Serving	Term Ends
Daniel Hall Chairman	D	09/2013	09/2019
Stephen Stoll	D	06/2012	12/2017
Bill Kenney	R	01/2013	01/2019
Scott Rupp	R	04/2014	04/2020
Maida Coleman	D	08/2015	08/2021

Miscellaneous Issues

Gubernatorial Election — Gov. Nixon was not permitted to seek reelection due to term limits. On Nov. 8, 2016, former U.S. Navy SEAL Eric Greitens, a Republican, defeated Attorney General Chris Koster, a Democrat, in the gubernatorial election; Mr. Greitens will begin serving in January 2017.

Commissioner Selection Criteria — Minority party representation is practiced, but not required.

Services Regulated — In addition to regulating electric, gas, steam, water, and sewer utilities, the PSC has authority over rural electric cooperatives — only with regard to safety — and manufactured housing — with regard to building code compliance — and has limited authority over retail telecommunications.

Staff Contact: Kevin Kelly, Public Information Administrator (573) 751-9300 (Section updated 11/9/16)

RRA Evaluation

Historically, Missouri regulation has been relatively balanced from an investor perspective. ROEs adopted by the PSC over the past year or so were slightly below prevailing industry averages at the time established. All of the large electric utilities have fuel adjustment clauses, or FACs, in place that allocate a portion of fuel and purchased power-related cost variations to shareholders. However, in three electric rate proceedings decided in 2015, and one case decided in 2016, the PSC prohibited the companies from prospectively recovering a portion of their transmission costs through their FACs. In the gas arena, the state's local gas distribution companies are permitted to adjust rates to reflect changes in gas commodity costs on a timely basis, and the commission has approved the use of surcharges for recovery of infrastructure improvement costs between base rate cases. RRA recently affirmed its Average/2 ranking of the jurisdiction, but noted that it is mindful of the fact that the 2016 legislative session concluded without action being taken on a bill that would have altered the state's ratemaking framework to address concerns regarding "regulatory lag." The issue is of particular concern to Missouri's electric utilities, and the matter is now being considered both by an interim legislative committee and the PSC in a working docket. Although the utilities are generally supportive of potential changes to the regulatory paradigm, recent comments from the public counsel were dismissive of regulatory lag concerns. Separately, the staff has suggested that the commission should exercise authority over Great Plains Energy's proposed acquisition of Westar Energy, despite the companies' public assurances that PSC approval is not required for the transaction to be consummated. Should the legislature or PSC fail to take action to address regulatory lag concerns, or if the Great Plains/Westar deal ultimately comes before the PSC in a contentious proceeding, a reduction in RRA's ranking may be justified. (Section updated 10/6/16)

RRA Ranking History

Date of Ranking Change	RRA Ranking
1/8/2008	Average / 2
10/13/1993	Average / 3
1/1/1993	Below Average / 1
1/6/1989	Average / 2
10/5/1987	Average / 3
5/16/1986	Below Average / 1
2/1/1984	Average / 3
7/19/1983	Below Average / 1
7/2/1982	Below Average / 2

RRA maintains three principal rating categories for regulatory climates: Above Average, Average, and Below Average. Within the principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger rating; 2, a mid-range rating; and, 3, a weaker rating. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by the jurisdiction's utilities. The evaluation reflects our assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.

Consumer Interest

Represented by the Office of the Public Counsel, a division of the Department of Economic Development, or DED. The public counsel is appointed by the director of the DED for an unspecified term. (Section updated 10/6/16)

Rate Case Timing/Interim Procedures

Utilities seeking to increase rates must file tariffs 30 days prior to the proposed effective date. The proposed tariffs may then be suspended by the PSC for 10 months. If the commission has not issued a final decision within 11 months of the initial filing, the proposed rates would become effective as filed and would not be subject to refund. The PSC may authorize an interim increase, subject to refund, if a company can demonstrate an emergency, or a near emergency situation. Interim increases have rarely been sought or authorized. (Section updated 10/6/16)

Return on Equity

The most recent electric rate decision that specified an ROE was issued in September 2015, when the PSC authorized Great Plains Energy subsidiary Kansas City Power & Light, or KCP&L, a 9.5% ROE. Ameren subsidiary Union Electric, or UE, d/b/a Ameren Missouri, is authorized a 9.53% ROE, as established in an April 2015 rate case decision. The most recent ROE determination for Great Plains Energy subsidiary KCP&L-Greater Missouri Operations, or GMO, occurred in 2013, when the PSC established a 9.7% ROE for the company. A case for GMO that was decided in September 2016, was resolved by a settlement that indicated that the stipulated rate change reflected an ROE in a range of 9.5% to 9.75%. The most recent electric decision for Empire District Electric that specified an ROE was issued in 2008, when the PSC established a 10.8% ROE. A case for Empire that was decided in August 2016, was resolved by a settlement that indicated that the stipulated rate change reflected an ROE in a range of 9.5% to 9.9%.

The most recent gas rate decision that specified an ROE was issued in December 2014, when the PSC authorized Liberty Utilities (Midstates Natural Gas), d/b/a Liberty Utilities, a 10% ROE. Liberty Utilities was formerly known as Atmos Energy. In 2014, the PSC authorized Summit Natural Gas of Missouri a 10.8% ROE.

For the other gas utilities, rate decisions in recent years have followed settlements that were silent regarding authorized ROEs for their overall operations. However, in certain circumstances, those utilities have riders in place that reflect PSC approved equity returns (see the Adjustment Clauses section). The most recent gas rate decision that specified an ROE for Laclede Group subsidiary Missouri Gas Energy, or MGE, was issued in 2010, when the PSC authorized a 10% ROE; however, MGE uses a 9.75% pre-tax weighted average cost of capital to calculate rate adjustments under its infrastructure system replacement surcharge, or ISRS, rider. A 2013 PSC-approved rate case settlement specifies that Laclede Group subsidiary Laclede Gas, or LGC, is to use a 9.7% ROE to calculate prospective rate adjustments under the company's ISRS rider. UE is permitted to utilize a 10% ROE in the context of its ISRS rider. (Section updated 10/6/16)

Rate Base and Test Period

The PSC generally relies on a year-end original-cost rate base, but, by law, must consider fair value. Rate requests are typically filed based on historical or partly forecasted test period data, which are updated during the course of the proceeding to reflect actual results. The adopted test periods are historical at the time of PSC decisions; however, limited "known-and-measurable" changes beyond the end of the test period may be recognized. By law, the PSC is prohibited from including electric construction-work-in-progress in rate base. (Section updated 10/6/16)

Accounting

Union Electric, or UE, and Kansas City Power & Light, or KCP&L, are permitted to collect from ratepayers amounts to fund the eventual decommissioning of the Callaway and Wolf Creek nuclear facilities, respectively; these funds are placed in qualified external decommissioning trusts. UE owns 100% of Callaway and KCP&L owns 47% of Wolf Creek.

UE, KCP&L, KCP&L Greater Missouri Operations, or GMO, Empire District Electric, Laclede Gas, Missouri Gas Energy, or MGE, and Liberty Utilities (Midstates Natural Gas), formerly Atmos Energy, are permitted to track, as regulatory assets/liabilities, incremental variations in pension-related costs and other post-employment benefits. UE, KCP&L, GMO, Empire, MGE and Liberty Utilities are permitted to record, as regulatory assets, costs related to energy efficiency programs that were not previously approved by the PSC under the Missouri Energy Efficiency Act. Empire is permitted to track non-labor O&M costs associated with the Riverton 12 plant. (Section updated 10/6/16)

Alternative Regulation

Empire District Electric, Kansas City Power & Light, or KCP&L, KCP&L Greater Missouri Operations, and Union Electric have fuel adjustment clauses in place that allocate, on a 95%/5% basis to ratepayers and shareholders, incremental fuel-cost variations (see the Adjustment Clauses section).

Missouri Gas Energy has in place a framework that provides for sharing of a portion of off-system sales, or OSS, margins and capacity release, or CR, revenues, specifically: for the first $1.2 million of OSS margins and CR revenues, 15% is to be allocated to the company and 85% to customers; for the next $1.2 million, 20% is to be allocated to the company and 80% to customers; for the next $1.2 million, 25% is to be allocated to the company and 75% to customers; and, above $3.6 million, 30% is to be allocated to the company and 70% to customers.

Laclede Gas is permitted to retain 10% of any gas-cost savings relative to an established benchmark, up to a maximum of $3 million. In addition, the company shares with ratepayers, to varying degrees, OSS margins and CR revenues. Specifically: the first $2 million of OSS margins and CR revenues were entirely allocated to ratepayers from Oct. 1, 2013 through Sept. 30, 2016; beginning Oct. 1, 2016, the first $2 million of OSS margins and CR revenues are to be allocated 85%/15% to ratepayers and shareholders; incremental margins between $2 million and $4 million are to be shared 80%/20%; incremental margins between $4 million and $6 million are to be shared 75%/25%; and, incremental margins above $6 million are to be shared 70%/30%.

In a pending working docket, the PSC is considering the merits of certain alternative ratemaking techniques that could be utilized to address the adverse effects of regulatory lag on the state's utilities. The staff is expected to file a report in the near future on the matter, and the commission will report its findings to the General Assembly for consideration during the 2017 legislative session. (Section updated 10/6/16)

Court Actions

PSC rate orders may be appealed directly to the Missouri Court of Appeals, or MCA, and ultimately to the Supreme Court of Missouri, or SCM. Rates essentially cannot be stayed by the MCA; however, the court has the authority to require the PSC to amend a company's rates based on the court's ruling. The governor initially appoints judges to the SCM and the MCA from nominations submitted by judicial selection commissions. Supreme and appeals court judges must run for retention of office at the end of a 12 year term.

No major utility related issues have been before the courts in the past couple of years. (Section updated 10/6/16)

Legislation

The Missouri General Assembly is a bicameral body that meets annually beginning in January and continuing into May. Annual veto sessions are held in September, whereby bills vetoed by the governor during the prior regular session are considered by the legislature for possible override. Currently there are 115 Republicans, 45 Democrats, one Independent and two vacancies in the House of Representatives; there are 24 Republicans, 7 Democrats and three vacancies in the Senate.

The 2016 regular session concluded in May 2016, without action being taken on legislation that would have modified the ratemaking paradigm currently in place for the state's electric utilities. Senate Bill 1028 had called for implementation of policies that would have addressed "regulatory lag" — primarily through the use of a "performance-based" ratemaking, or PBR, framework — encouraged investment in the state's electric infrastructure and provided "globally competitive" electric rates for "energy intensive customers." The bill also called for implementation of certain customer protections, including earnings caps, rate caps and utility performance standards, and would have permitted the utilities to recover variations in transmission related costs between base rate proceedings, through an adjustment clause. House Bill 2689 included similar provisions, but did not call for the creation of a PBR framework.

The General Assembly is to reconvene in January 2017. (Section updated 10/6/16)

Corporate Governance

By law, the PSC has authority over mergers and reorganizations involving the utilities it regulates, certain financing arrangements, and affiliate issues. The PSC has, in some instances, adopted ring-fencing provisions in the context of approving proposed mergers (see the Merger Activity section).

Reorganizations — In 2001, the PSC conditionally authorized Kansas City Power & Light, or KCP&L, to restructure its operations into a holding company, Great Plains Energy, with subsidiaries that included KCP&L and its regulated operations. The PSC imposed the following conditions: KCP&L's common stock cannot be pledged as collateral for Great Plains Energy's debt without PSC approval; KCP&L cannot guarantee the notes, debentures, debt obligations, or other securities of Great Plains Energy or its subsidiaries without PSC authorization; Great Plains Energy is to maintain a common equity ratio of at least 30%, and KCP&L's common equity ratio must be at least 35%; KCP&L's total long-term debt is not to exceed rate base, and must remain separate from the holding company; and, KCP&L is to maintain an investment-grade credit rating.

Also in 2001, the PSC conditionally authorized Laclede Gas to restructure its operations into a holding company, Laclede Group, with subsidiaries that included Laclede Gas and its regulated operations. (Section updated 10/6/16)

Merger Activity

In approving a proposed merger, the PSC must determine that the transaction is "not detrimental to the public interest." There is no statutory timeframe within which the commission must render decisions on proposed mergers.

Since the late 1990s, the PSC has ruled on a number of mergers and asset transfers. In 1997, the PSC approved the merger of Union Electric, or UE, and Central Illinois Public Service, or CIPS, to form Ameren. The merger closed in 1997. In 2005, the PSC affirmed a previous decision in which it conditionally approved Ameren's proposal to transfer UE's Illinois electric and gas distribution assets to CIPS at book value ($138 million). The PSC's conditions pertained to the treatment of certain pre-transfer liabilities and off-system sales issues. A related service territory transfer was completed later in 2005, and UE now operates solely in Missouri. The PSC did not have jurisdiction over Ameren's 2003 and 2004 acquisitions of Illinois utilities Central Illinois Light and Illinois Power, respectively, as there was no change in control of a utility subject to its oversight.

In 1999, the PSC approved the merger of American Electric Power and Central and South West following a settlement that resolved the commission's concerns regarding the effect of the merger on retail competition in Missouri related to the companies' capacity reservation on Ameren's transmission system. The merger closed in 2000.

In 2000, UtiliCorp United, subsequently known as Aquila, and St. Joseph Light & Power merged following PSC approval. However, the commission rejected a related five-year alternative regulation plan. In 2004, the PSC determined that UtiliCorp should not be allowed to recover the associated acquisition premium from customers; the commission stated that it has consistently applied the net original-cost standard when placing a value on assets for purposes of establishing a utility's rates.

In 2008, KCP&L parent Great Plains Energy acquired Aquila, following conditional approval by the PSC. The former Aquila utilities in Missouri are now known as KCP&L Greater Missouri Operations. The conditions include the following: Great Plains will not be permitted to recover from ratepayers any transaction costs associated with the merger; the companies are to track merger-related synergies to demonstrate whether actual synergies exceed the transition costs associated with the merger—the company utilized regulatory lag to retain its share of synergies, and ratepayers share of the synergies have been reflected in rates through rate cases filed subsequent to the completion of the transaction; any post-merger "financial effect" of a credit downgrade of Great Plains, KCP&L, and/or Aquila, that occurs as a result of the merger is to be "borne by the shareholders"; and, the PSC "reserves the right to consider any ratemaking treatment" to be accorded the transactions in a future proceeding. In the company's 2011 rate case decision, the PSC determined that actual synergies exceeded the merger's transition costs and allowed the company to amortize these costs over a five-year period.

In an Aug. 3, 2016 order, the PSC required that a proceeding be closed in which it had been addressing certain issues pertaining to Great Plains' proposed acquisition of Westar Energy. The staff had contended that a 2001 PSC order that permitted KCP&L to restructure its operations into the Great Plains holding company effectively gives the commission jurisdiction over the deal. The company countered the staff's claim, and the PSC determined in its Aug. 3 order that the proceeding was only an "investigatory docket, not a case, contested or otherwise." The commission stated that it would be inappropriate to require any particular remedy since other parties had not been given an opportunity to present their positions on the matter. It is unclear whether the staff intends to file a contested case that could allow the PSC to exercise jurisdiction over the proposed acquisition.

In 1997, Atmos Energy acquired United Cities Gas following PSC approval. In 2004, Atmos acquired former TXU Inc. subsidiary TXU Gas, following PSC approval of a settlement specifying that: the acquisition premium may not be recovered from ratepayers; company books and records continue to be available for review by the PSC Staff and the Office of Public Counsel; and, Atmos would issue at least $300 million of new equity to partially fund the acquisition. Atmos' equity issuance later in 2004 generated $235 million in net proceeds. The transaction closed in 2004.

In 2012, Atmos sold its Missouri-jurisdictional utility assets to Liberty Energy (Midstates) Corp., an affiliate of Algonquin Power & Utilities Corp., following PSC approval of a related settlement. The transaction also involved the sale of Atmos' Illinois and Iowa utility assets to Liberty Energy. The approved settlement provides for Liberty to maintain Atmos' existing tariffs. The transaction closed later in 2012, and the new entity is known as Liberty Utilities (Midstates Natural Gas), d/b/a Liberty Utilities.

In 2006, the PSC authorized Empire District Gas, or EDG, to acquire Aquila's Missouri-jurisdictional gas utility operations following a settlement that imposed a three-year base rate freeze.

On Sept. 7, 2016, the PSC adopted several settlements, thereby approving Algonquin Power and Utilities' proposed acquisition of EDG parent Empire District Electric. The transaction is pending receipt of certain other required regulatory approvals.

In 2012, Energy Transfer Equity, or ETE, acquired Southern Union following PSC approval of a related settlement. The approved settlement specified, among other things, that: Southern Union was to be prohibited from guaranteeing certain debts incurred by ETE affiliate Energy Transfer Partners in conjunction with the transaction; the debt of any affiliate was to be non-recourse to Southern Union; Southern Union's equity was not to be pledged as collateral for the debt of any affiliate or non-affiliate; Southern Union was to maintain records separate from its affiliates; Southern Union was to be prohibited from commingling its utility system with any other entity or maintain its system such that it would be "costly or difficult" to separate its assets from those of an affiliate; Southern Union was to continue to be subject to certain customer service performance measures and maintain certain operating procedures; Southern Union agreed to ensure that the company's retail gas distribution rates would not increase as a result of the merger; any adverse impact of the merger on Southern Union's credit ratings would deserve "consideration" by the PSC in future proceedings; the acquisition premium and the transaction and transition costs associated with the merger were not to be recoverable in retail distribution rates; and, Southern Union was to continue its service-line and main replacement programs.

In 2013, Southern Union division Missouri Gas Energy, or MGE, was acquired by a subsidiary of the Laclede Group. The PSC had approved a related settlement specifying, among other things, that: MGE is to record a $125 million "rate base offset" and will be permitted to amortize this amount over a ten-year period; the company is prohibited from recovering, from its retail distribution customers, any acquisition premium and transaction-related costs; affiliate Laclede Gas, or LCG, and MGE will not seek an increased cost of capital as a result of the transaction; LCG is prohibited from pledging its equity as collateral for the debt of any affiliate without first receiving PSC approval for such action; and, if the parent company's non-regulated operations were to be the cause of a downgrade in LCG's credit ratings to below investment-grade, LCG would be required to pursue additional "legal and structural separation" from the parent to ensure that LCG has "access to capital at a reasonable cost."

In 2013, the PSC terminated its review of a proposed transaction that had called for Entergy Corp.'s utility operating companies to spin off their electric transmission assets, with those assets subsequently to be acquired by ITC Holdings. The companies had previously requested that their proposal be withdrawn in light of their inability to obtain regulatory approval for the deal in another jurisdiction.

On Sept. 14, 2016, the PSC adopted a settlement, thereby approving Fortis Inc.'s proposed acquisition of ITC Holdings and its subsidiary ITC Midwest, which is subject to PSC oversight with respect to the safety of a transmission line in Missouri. The deal is pending receipt of certain other required regulatory approvals. (Section updated 10/6/16)

Electric Regulatory Reform/Industry Restructuring

Comprehensive retail competition has not been implemented. However, a large industrial customer, Noranda Aluminum, is permitted to contract for the purchase of electricity and delivery services outside of the PSC's jurisdiction. Noranda currently receives service from Union Electric. (Section updated 10/6/16)

Gas Regulatory Reform/Industry Restructuring

Local gas distribution companies, or LDCs, have offered transportation-only service since the late-1980s. Missouri Gas Energy offers transportation -only service to customers with gas usage of at least 2,000 MCF in any one month or annual usage of at least 30,000 CCF. Laclede Gas offers a transportation rate to customers that have annual gas usage of at least 30,000 MCF. Union Electric offers two transportation rates: a "standard rate" for certain customers with annual usage of less than 60,000 MCF; and, a "large-volume rate" for all other customers. Empire District Gas offers transportation-only service to customers with annual gas usage of at least 15,000 MCF. Liberty Utilities (Midstates Natural Gas) offers transportation-only service to customers with gas usage of at least 1,550 MCF in a single month. All of the state's LDCs offer transportation-only service to schools on an aggregated basis. No action has been taken with regard to retail choice for small-volume customers. (Section updated 10/6/16)

Adjustment Clauses

State statutes permit the electric utilities to request PSC approval of mechanisms that allow for the expedited recovery of costs related to fuel and purchased power, environmental compliance, renewable energy, gas commodity costs, energy efficiency costs, and certain other items.

Fuel Adjustment Clauses, or FACs — According to the PSC's rules: an application for approval of an FAC must be submitted within the context of a general rate case or complaint proceeding; an FAC should provide the utility an opportunity to earn a "fair return on equity"; the commission may adjust a utility's allowed ROE in future rate proceedings if it determines that implementation of an FAC would alter the utility's business risk; incentive features may be incorporated into an FAC to improve the efficiency and cost-effectiveness of a utility's fuel and purchased power procurement activities; an FAC is to be subject to true-ups for under- and over-collections, including interest; an FAC may reflect incremental variations in off-system sales, or OSS, revenues; an FAC may remain in place for a maximum four-year term, unless the PSC authorizes an extension or modification of the FAC in the context of a general rate case, i.e., the utility must file a rate case within four years after implementation, extension, or modification of an FAC; and, such mechanisms are to be subject to a prudence review no less frequently than every 18 months.

KCP&L Greater Missouri Operations', or GMO's, FAC has 12-month recovery periods and provides for the company to recover from/flow to ratepayers 95% of incremental variations in "prudently incurred" fuel and purchased power costs, net emissions allowance costs, and OSS revenues from the levels included in base rates.

Empire District Electric utilizes an FAC that provides for the company to recover from/flow to ratepayers, on a semi-annual basis over six-month recovery periods, 95% of incremental variations in fuel and purchased power costs, net emissions allowance costs, and OSS revenues from the levels included in base rates. In a June 2015 rate case decision, the PSC required that a portion of the transmission costs Empire incurs related to its participation in the Southwest Power Pool, or SPP, market be excluded from its FAC. The commission determined that the transmission costs Empire can include in its FAC are: costs incurred to transmit power, to serve its native load, that is sourced from generation plants not owned by the company ("true purchased power"); and, costs incurred to transmit excess power the company sells to third parties in locations outside of SPP (off-system sales). The PSC prohibited the company from recovering through the FAC costs related to the power that the company produces, sells into the SPP market, and subsequently repurchases for its native load.

Union Electric, or UE, utilizes an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in fuel and purchased power costs, net emissions allowances, and OSS revenues from the levels included in base rates. UE's FAC incorporates three adjustments per year and eight-month-long recovery periods. In an April 2015 rate case decision, the PSC determined that the transmission costs UE can include in its FAC are: costs incurred to transmit power, to serve its native load, that is sourced from generation plants not owned by the company (true purchased power); and, costs incurred to transmit excess power the company sells to third parties in locations outside of SPP (off-system sales). The PSC prohibited the company from recovering, through the FAC, costs related to the power that the company produces, sells into the SPP market, and subsequently repurchases for its native load.

In a September 2015 rate case decision, the PSC authorized Kansas City Power & Light, or KCP&L, to implement an FAC that provides for the company to recover from/flow to ratepayers 95% of incremental variations in fuel and purchased power costs, net emissions allowances, and OSS revenues from the levels included in base rates. The commission determined that the transmission costs KCP&L can include in its FAC are: costs incurred to transmit power, to serve its native load, that is sourced from generation plants not owned by the company, i.e., true purchased power; and, costs incurred to transmit excess power the company sells to third parties in locations outside of SPP, i.e., off-system sales. The PSC prohibited the company from recovering through the FAC costs related to the power that the company produces, sells into the SPP market, and subsequently repurchases for its native load.

Environmental Cost Recovery Mechanisms, or ECRMs — The PSC's rules pertaining to ECRMs are similar to those in place for FACs, and specify that: the commission may consider the magnitude of costs eligible for inclusion in an ECRM and the ability of the utility to manage these costs, when determining which cost components to include in an ECRM; a portion of the utility's environmental costs may be recovered through an ECRM and a portion may be recovered through base rates; the annual recovery of environmental compliance costs is to be capped at 2.5% of the utility's Missouri gross jurisdictional revenues, less certain taxes; a utility that uses an ECRM must file for at least one, and no more than two, annual adjustments to its ECRM rate; adjustments must be made to a utility's ECRM rates within 60 days from the time of filing, if such adjustments adhere to state statutes; an ECRM may remain in place for a maximum four-year term, unless the PSC authorizes an extension in the context of a general rate case — the utility must file a general rate case within four years after implementation of an ECRM; and, such mechanisms are to be subject to a prudence review every 18 months and an annual true-up for under- and over-collections, including interest. None of the utilities currently have an ECRM in place; however, Empire, KCP&L, GMO, and UE recover emissions allowance costs through their FACs.

Energy Efficiency — KCP&L, GMO, and UE have in place demand-side program investment mechanisms that provide for recovery of program-related costs and the related lost revenues and may provide for a performance incentive based upon measurable and verified energy efficiency savings.

Renewable Energy — The PSC's rules specify that the electric utilities may file, in the context of a rate case or in a generic proceeding, for a Renewable Energy Standards rate adjustment mechanism, or RESRAM, that would allow for rate adjustments to provide for recovery of prudently incurred costs or a pass-through of benefits received, as a result of compliance with the state's renewable energy standards. Rate increases under the RESRAM are to be capped at 1% annually; there is no limit to the credit that can be included in the RESRAM. Any costs incurred by the utility that are in excess of the cap are to be deferred for future recovery and a carrying charge is to apply to the balance. GMO has a RESRAM in place.

Other Electric — GMO and UE use a rider to recover costs associated with certain government-mandated investments. Empire, KCP&L, GMO and UE have a mechanism in place to recover variations in certain taxes and franchise fees.

Purchased Gas Adjustment, or PGA, Clauses — Local gas distribution companies, or LDCs, are authorized to reflect changes in gas costs through a PGA clause, with up to four adjustments permitted each year. Differences between actual costs incurred and costs reflected in rates are deferred and recovered from, or credited to, customers over a subsequent 12-month period. The companies are permitted to use financial hedging instruments to mitigate the effects of gas-price volatility, and the PSC has implemented a rule that identifies the types of hedging mechanisms that should be considered. The LDCs may request PSC approval of a mechanism to reflect the impact of changes in customer usage due to variations in weather and/or conservation; however, none of the utilities currently have such a mechanism in place. Laclede Gas, or LGC, and Missouri Gas Energy, or MGE, share OSS margins and capacity release revenues with ratepayers, with the related impacts reflected in the PGA clause (see the Alternative Regulation section).

Decoupling — The LDCs are permitted to request PSC approval of a mechanism to reflect the impact of changes in customer usage due to variations in weather and/or conservation. None of the LDCs currently has such a mechanism in place.

In July 2015, the PSC established a working docket to consider the merits of establishing revenue decoupling mechanisms for the electric and natural gas utilities. The proceeding is pending.

Other Gas — LGC, UE, MGE and Liberty Utilities (Midstates Natural Gas) utilize an infrastructure system replacement surcharge to recover costs associated with certain distribution system replacement projects. Liberty Utilities, Empire, Laclede, MGE and UE have a mechanism in place to recover variations in certain taxes and franchise fees. (Section updated 10/6/16)

Integrated Resource Planning

The state's four investor-owned electric utilities that serve retail customers, namely Union Electric, or UE, Kansas City Power & Light, or KCP&L, KCP&L Greater Missouri Operations, or GMO, and Empire District Electric are required by the commission's rules to file 20-year resource plans every three years with annual updates. In these filings, the utility must consider demand-side measures on an equivalent basis with supply side alternatives, and analyze and quantify the risks associated with such factors as: future environmental regulations; load growth; fuel prices and availability; construction costs and schedules; and, demand-side program load impacts.

The Missouri Energy Efficiency Investment Act, which requires the PSC to allow the electric utilities to implement demand-side programs and recover the related costs, became law in 2009 and the PSC's related rules became effective in 2011. The law does not establish specific thresholds for demand-side-program-related savings. In 2012, the commission approved a unanimous stipulation and agreement approving the following for UE: a demand-side-management plan for residential and commercial customers, beginning in 2013, a related tracker to provide for $80 million in revenue — ultimately reflected in UE's 2012 general rate proceeding — for recovery of program costs and recovery of lost fixed costs and to allow the company to earn a performance incentive based on after-the-fact verified energy savings from the programs; and, annual evaluation, measurement and verification of such programs' processes and energy and demand savings performed by an independent contractor with reported results audited by the commission's independent auditor. The tracker was replaced by a rider in 2014.

In 2012, the PSC approved a settlement for GMO that provides for: a demand-side-management plan for residential and commercial customers, that became effective in 2013, a related tracker to provide for $18 million in revenue — ultimately reflected in GMO's 2012 general rate proceeding — and recovery of lost fixed costs, and which allow the company to earn a performance incentive award based on after-the-fact verified energy and demand savings from the programs; and, annual evaluation, measurement and verification of such programs' processes and energy and demand savings performed by an independent contractor with reported results audited by the commission's independent auditor.

In 2014, the PSC approved a settlement for KCP&L that provides for: a demand-side-management plan, for residential and commercial customers, that became effective later in 2014, a related investment recovery mechanism to allow recovery of actual program costs and lost fixed costs, and which allow the company to earn a performance incentive award based on after-the-fact verification of energy and demand savings from the programs; and, annual evaluation, measurement and verification of such programs processes and energy and demand-savings performed by an independent auditor. (Section updated 10/6/16)

Renewable Energy

State statutes include a renewable energy standard, or RES, that required Missouri-jurisdictional investor-owned electric utilities to obtain at least 2% of their generation from renewable resources in calendar-years 2011 through 2013, with the threshold rising to 5% in calendar-years 2014 through 2017, to 10% in calendar-years 2018 through 2020, and to 15% in 2021 and thereafter. Eligible renewable resources include solar, wind, biomass and certain hydropower facilities, and at least 2% of each year's renewable-energy-related portfolio requirement is to be from solar resources. RES-related rules subsequently adopted by the PSC: include a restriction that adherence to the standard would result in a rate increase of no more than 1%; provide for penalties for non-compliance; and, include a provision for recovery outside the context of a general rate case for the "prudently incurred costs and the pass-through of benefits to customers of any savings achieved" in complying with the measure (see the Adjustment Clauses section). The utilities are permitted to purchase renewable energy credits to satisfy their obligations under the law.

The statute was subsequently modified to include a tiered approach to reducing applicable solar rebate amounts from $2 per watt for systems that became operational by June 30, 2014, to zero cents per watt after June 30, 2020, and provisions to allow the electric utility to cease paying rebates in any calendar year in which the maximum average retail rate impact will be reached. As a condition of receiving a rebate, customers are required to transfer to the electric utility all rights, title and interest in and to the renewable energy credits for a period of 10 years. Subsequent settlements approved by the PSC designated a total of $178.4 million for solar rebates in Missouri for the three electric utilities that offered rebates at that time. In April 10, 2015, the Missouri Supreme Court determined that the statutory exemption from payment of solar rebates upon which Empire District Electric had relied had previously been repealed. In accordance with the Court's directive, Empire began offering solar rebates in May 2015. (Section updated 10/6/16)

Emissions Requirements

Legislation enacted in 2014 allows the Missouri Air Conservation Commission to develop less-stringent carbon-reduction standards than those included in the U.S. Environmental Protection Agency's, or EPA's, proposed carbon emissions rule for existing power plants. A "unit-by-unit analysis" is to be conducted to determine the appropriate means of compliance that, among other things, considers the cost of installing emissions-reduction equipment and the economic impact that a closure of a plant could have on the region.

In August 2015, the EPA released the final version of its Clean Power Plan, or CPP. The CPP calls for a 32% reduction nationwide in the domestic power sector's carbon dioxide emissions by 2030, versus 2005 levels. For Missouri, the plan requires a 37% reduction. Many states, including Missouri, have challenged the legality of the rule, which has been stayed by the U.S. Supreme Court, pending the outcome of a review by U.S. Court of Appeals for the District of Columbia Circuit. Initial briefs before the Circuit Court are to be filed in October 2016, with final briefs due Feb. 6, 2017. (Section updated 10/6/16)

Rate Structure

The major electric utilities have seasonally differentiated rates in place, and all of the electric utilities have some form of time-of-day rates in effect. The PSC has authorized discounted economic development electric rates for new or expanding industrial and commercial customers.

In an April 2015 rate case decision that addressed certain economic development issues related to Union Electric's, or UE's, largest customer, Noranda Aluminum, the PSC established a $36/MWH base rate for Noranda and declined to eliminate the fuel adjustment clause, or FAC, charges for the company; however, prospective FAC rate adjustments applicable to Noranda are to be capped at $2/MWH. In addition, the commission noted its "intent" that base rate increases for Noranda over the next three years will be limited to 50% of the system average increase authorized, and its base rates would remain unchanged if the PSC were to order a base rate reduction for UE. Any revenue deficiency resulting from these provisions are to be proportionally allocated to UE's other ratepayers. At the time, the PSC found that it was "in the interest of all ratepayers for the commission to allow Noranda a lower rate to keep it as a customer" of UE.

In 2014, the PSC adopted a settlement that required Missouri Gas Energy, or MGE, to terminate its straight-fixed variable, or SFV, rate design for the residential and small commercial customer classes, whereby all of the company's fixed costs allocable to those customer classes were recovered through a fixed, monthly customer charge. MGE now recovers a portion of its fixed costs through the volumetric rate.

Laclede Gas has a seasonally-differentiated rate in place. In 2010, the PSC adopted a settlement that required Liberty Utilities (Midstates Natural Gas) to terminate its SFV rate design and utilize a traditional rate design under which a portion of fixed costs are recovered through volumetric charges. (Section updated 10/6/16)

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Research Update:

Great Plains Energy Inc. Ratings Affirmed, Outlook Revised To Negative On Proposed Acquisition Of Westar Energy

Primary Credit Analyst:
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@spglobal.com

Secondary Contact:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

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Research Update:

Great Plains Energy Inc. Ratings Affirmed, Outlook Revised To Negative On Proposed Acquisition Of Westar Energy

Overview

- Great Plains Energy Inc. (GPE) announced it will acquire Westar Energy Inc. for about $8.6 billion, plus the assumption of Westar's debt. The parties expect the transaction to close by mid-2017.
- We are affirming our 'BBB+' issuer credit ratings on GPE and subsidiaries Kansas City Power & Light Co. and KCP&L Greater Missouri Operations Co. and for all three entities revising the outlook to negative from stable.
- The negative outlook reflects the potential for lower ratings if GPE's financial risk profile, which will deteriorate due to financing used in the acquisition, does not improve after the transaction closes such that funds from operations to total debt is well over 13% after 2018.

Rating Action

On May 31, 2016, S&P Global Ratings affirmed its ratings on Great Plains Energy Inc. (GPE) and subsidiaries Kansas City Power & Light Co. (KCP&L) and KCP&L Greater Missouri Operations Co. (GMO), including the 'BBB+' issuer credit ratings, and revised the outlook to negative from stable for all entities.

Rationale

The ratings affirmation on GPE and its subsidiaries reflects our view that the Westar acquisition will enhance GPE's business risk profile given that Westar's operations also consist of regulated electric utilities that benefit from operations under a generally constructive regulatory framework and service territories with average customer growth.

The outlook revision to negative reflects our view that GPE's financial risk profile will weaken due to the proposed financing, pressuring GPE's overall credit profile for the next few years. We expect that after the acquisition closes, the combined entity's financial profile will strengthen mainly due to ongoing regulatory recovery of costs such that funds from operations (FFO) to total debt is consistently above 13%. In addition to assuming Westar's debt, GPE plans to fund the acquisition price of about $8.6 billion with common equity, mandatory convertible preferred stock, Great Plains common stock, and debt.

We view GPE's business risk as excellent, which incorporates the very low risk of a regulated utility focused on U.S. operations and markets. In addition, the business risk profile reflects a competitive position based on utility subsidiaries KCP&L, which serves about 527,000 electricity customers in and around Kansas City and its suburbs, and GMO, which serves about 300,000 electricity customers in western Missouri. The company operates with generally supportive regulation, a mainly residential customer base that supports cash flow stability good operating efficiency, and an absence of competition. Riders and mechanisms exist for the recovery of fuel costs, transmission charges, and energy-efficiency costs. GPE continues to focus on a regulated business strategy in pursuing similarly regulated Westar.

Prospectively, the combined entity would have more diverse electric utility cash flow sources, strengthening the excellent business risk profile. GPE's customer mix would shift from being about three-quarters in Missouri before the Westar transaction to about 40% after the closing, with Kansas customers making up the difference. The customer base would be further bolstered with an almost doubling of customers, which would mitigate exposure to any one industry, and would boost the base level of usage from the combined 1.55 million largely residential and commercial customers. GPE's stand-alone rate base mix would shift from about 65% in Missouri and 30% in Kansas, with the remainder under Federal Energy Regulatory Commission (FERC) jurisdiction, to 55% Kansas, 32% Missouri, and the remainder under FERC regulation.

Based on the medial volatility financial ratio benchmarks, our assessment of GPE's financial risk profile is within the middle of benchmark ratios for an assessment of significant. We expect these financial measures to weaken considerably when the merger closes. Under our pro forma scenario, following the completion of the Westar acquisition, we would expect FFO to debt of between 12% and 13% and that would subsequently strengthen, resulting in FFO to total debt of more than 14% after 2018.

Liquidity

GPE has an adequate liquidity assessment because we believe the company's liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and to meet cash outflows, even with a 10% decline in EBITDA. The adequate assessment also reflects the company's generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in credit markets.

There are modest debt maturities over the next three years, with $380 million due in 2017. We expect the company to refinance those given its satisfactory credit-market standing.

Principal Liquidity Sources

- Cash of about $10 million in 2016.
- We estimate FFO of about $800 million in 2016.
- Revolving credit facility availability of an estimated $1.25 billion in

2016.

Principal Liquidity Uses

- Capital spending of roughly $750 million expected in 2016.
- Dividends of about $175 million in 2016.
- Debt maturities, including outstanding commercial paper, of about $400 million in 2016.
- $174 million of outstanding letters of credit that back up variable-rate bonds due in 2018.

Other Credit Considerations

The ratings on GPE include a one-notch negative adjustment for comparable rating analysis. This adjustment accounts for an excellent business risk profile assessment that includes partial ownership of a single nuclear facility that has had operational issues and exposure to somewhat less-credit-supportive regulation in Missouri. Moreover, when the acquisition is complete, and in the first year, the core financial ratio of FFO to total debt is nearer the higher end of the aggressive benchmark range. We expect financial measures to strengthen modestly within the significant range, but remain well below the midpoint of this range.

Group Influence

We base our ratings on GPE on the consolidated group credit profile and application of our group ratings methodology. We consider GPE as the parent of the group with members KCP&L and GMO. We assess both operating utilities as core subsidiaries of GPE, reflecting our view that KCP&L and GMO are highly unlikely to be sold and have a strong long-term commitment from senior management. There are no meaningful insulation measures in place that protect KCP&L and GMO from their parent and therefore, KCP&L's and GMO's issuer credit ratings are in line with GPE's group credit profile of 'bbb+'.

We would consider operating utility Westar and its subsidiary Kansas Gas & Electric Co. (KG&E). as core entities of the GPE group. We believe the integrated electric utilities would be integral to GPE's long-term strategy and, therefore, the issuer credit ratings of Westar and KG&E would be in line with GPE's 'bbb+' group credit profile.

Outlook

The negative outlook on GPE and its subsidiaries reflects the potential for lower ratings if GPE's financial risk profile, which will deteriorate due to the financing used in the acquisition, does not improve after the transaction closes such that FFO to total debt is well over 13% after 2018.

Downside scenario

We could lower ratings on GPE and its subsidiaries if GPE's financial risk profile remains weak after the merger such that FFO to total debt is consistently below 13%. This could occur if the transaction is funded disproportionately with debt or if capital spending increases materially while investment recovery lags.

Upside scenario

We could affirm the ratings on GPE after the merger closes if the combined company demonstrates that it can achieve FFO to total debt of over 13% after 2018.

Ratings Score Snapshot

Corporate Credit Rating: BBB+/Negative/A-2

Business risk: Excellent
- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Significant
- Cash flow/Leverage: Significant

Anchor: a-

Modifiers
- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bbb+
- Group credit profile: bbb+

Issue Ratings

We rate the senior unsecured debt at GPE one notch lower than the issuer credit rating because priority liabilities, including operating utility debt, exceed 20% of total assets. We rate the preferred stock two notches below the issuer credit rating to reflect the discretionary nature of the dividend and the deeply subordinated claim if a bankruptcy occurs. The short-term rating is 'A-2', based on the company's issuer credit rating in our assessment of its liquidity as at least adequate.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov, 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Ratings List

Ratings Affirmed; Outlook Revised		
	To	From
Great Plains Energy Inc.		
Kansas City Power & Light Co.		
Corporate Credit Rating	BBB+/Negative/A-2	BBB+/Stable/A-2
KCP&L Greater Missouri Operations Co.		
Corporate Credit Rating	BBB+/Negative/--	BBB+/Stable/--
Issue Ratings Affirmed		
Great Plains Energy Inc.		
Senior Unsecured	BBB	
Preferred Stock	BBB-	
KCP&L Greater Missouri Operations Co.		
Senior Unsecured	BBB+	
Commercial Paper	A-2	
Kansas City Power & Light Co.		
Senior Secured	A	

Recovery Rating	1+
Senior Unsecured	BBB+
Commercial Paper	A-2

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at www.spcapitaliq.com. All ratings affected by this rating action can be found on the S&P Global Ratings public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

S&P Global
Ratings

RatingsDirect®

Summary:
Kansas City Power & Light Co.

Primary Credit Analyst:
Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@spglobal.com

Secondary Contact:
Safina Ali, CFA, New York (1) 212-438-1877; safina.ali@spglobal.com

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Summary:

Kansas City Power & Light Co.

Business Risk: EXCELLENT Vulnerable — Excellent	Anchor: a- Modifiers: a- Group/Gov't: a-	CORPORATE CREDIT RATING
Financial Risk: SIGNIFICANT Highly leveraged — Minimal		BBB+/Negative/A-2

Rationale

Business Risk: Excellent

- Regulated electric utility Kansas City Power & Light Co. (KCP&L) provides electricity in the greater Kansas City, Mo. metropolitan area.
- Relatively stable cash flows come from regulated electric operations.
- The regulatory framework in Kansas and Missouri is generally supportive.

Financial Risk: Significant

- Capital spending is declining.
- We expect financial measures to strengthen within the significant financial risk profile assessment.
- The company is committed to credit quality and maintaining a balanced capital structure.

Outlook: Negative

The outlook on KCP&L reflects the outlook on parent Great Plains Energy Inc. (GPE). The negative outlook on GPE and its subsidiaries reflects the potential for lower ratings if GPE's financial risk profile, which will deteriorate due to the financing used in the proposed acquisition of Westar Energy Inc., does not improve after the transaction closes such that funds from operations (FFO) to total debt is well over 13% after 2018.

Downside scenario

We could lower ratings on GPE and its subsidiaries if GPE's financial risk profile remains weak after the merger such that FFO to total debt is consistently below 13%. This could occur if the company funds the transaction disproportionately with debt or if capital spending increases materially while investment recovery lags.

Upside scenario

We could affirm the ratings on GPE after the merger closes if the combined company demonstrates that it can achieve FFO to total debt of more than 13% after 2018.

Standard & Poor's Base-Case Scenario

Assumptions

- Economic conditions in the company's service territory continue to improve incrementally, resulting in improving cash flow measures.
- Mid-single digit EBITDA growth rate over the forecast period.
- Adequate regulatory outcomes in Kansas and Missouri.
- Current rate surcharges are retained.

Key Metrics

	2015A	2016E	2017E
FFO/total debt (%)	17.4	17.0-18.8	17.5-19.0
Debt/EBITDA (x)	4.7	4.0-4.5	4.0-4.5
OCF/debt (%)	16.1	18.0-19.5	17.0-18.5

Note: Data represent S&P Global Ratings' adjusted figures. A--Actual. E--Estimate. FFO--Funds from operations. OCF--Operating cash flow.

Business Risk: Excellent

We base our assessment of KCP&L's business risk profile on what we view as the company's strong competitive position, very low industry risk stemming from the regulated utility industry, and the very low country risk stemming from the utility's U.S.-based operations. KCP&L's competitive position reflects the company's fully regulated integrated electric utility operations and our expectation for continued solid operational performance and generally credit-supportive regulation. The utility serves about 527,000 retail customers mainly in the greater Kansas City metropolitan area. The competitive position is also supported by an economically healthy service territory centered on a single metropolitan area with little industrial concentration, solid nuclear power operations, very low fuel costs, and lower electric rates. These attributes are partially offset by nuclear risks associated with the 47%-owned Wolf Creek station. The utility now operates with generally supportive regulation, cash flow stability from its customer base, and no competition.

Financial Risk: Significant

Based on our medial volatility financial ratio benchmarks, our assessment of KCP&L's financial risk profile is significant, reflecting the vertically integrated utility model and the recurring cash flow from selling electricity. As a utility, capital spending is ongoing for maintenance and for new projects. Recovery of these costs through rates has generally been supportive. We expect discretionary cash flow to turn positive over the next two years due to declining capital spending. Under our base case forecast, we expect FFO to total debt of about 18% to 19% and operating cash flow to debt to average about 18%, within the significant category.

Liquidity: Adequate

KCP&L has adequate liquidity. We believe the company's liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and to meet cash outflows, even with a 10% decline in EBITDA.

There are modest debt maturities over the next three years, with the next material maturity of $281 million in 2017. We expect the company to refinance these given its satisfactory standing in the credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• We estimate FFO of about $570 million. • Revolving credit facility availability at an estimated $600 million.	• Capital spending of roughly $500 million. • Dividends of about $80 million. • Short-term borrowings of about $195 million. • $170 million of outstanding letters of credit that back up variable-rate bonds due in 2018.

Other Credit Considerations

Our assessments of modifiers result in no further changes to the anchor score.

Group Influence

Under our group rating methodology, we assess KCP&L to be a core subsidiary of GPE, reflecting our view that KCP&L is highly unlikely to be sold and has a strong long-term commitment from senior management. There are no meaningful insulation measures in place that protect KCP&L from its parent and, therefore, KCP&L's issuer credit rating is in line with GPE's group credit profile of 'bbb+'.

Ratings Score Snapshot

Corporate Credit Rating

BBB+/Negative/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** bbb+
- **Entity status within group:** Core (-1 notch from SACP)

Recovery Analysis/Issue Ratings

- KCP&L's first mortgage bonds benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of more than 1.5x supports a recovery rating of '1+' and an issue rating two notches above the issuer credit rating.
- We rate KCP&L's senior unsecured debt the same as the issuer credit rating.
- The short-term rating on KCP&L is 'A-2' based on the company's issuer credit rating and our assessment of its liquidity as at least adequate.

Related Criteria And Research

Related Criteria

- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013

- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Stand-Alone Credit Profiles: One Component Of A Rating, Oct. 1, 2010
- Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery, Nov. 10, 2008
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

SNL Energy
FINANCIAL FOCUS

January 11, 2016

GREAT PLAINS ENERGY (GXP)

Key Statistics:

Pricing Information

Closing Price as of 1/7/2016	$27.24
Shares Outstanding (000s)	154,369
Market Cap. ($M)	4,205
Market/Book	115%
Return on Equity	6.3%

Earnings

Year Ended	EPS	P/E
12/31/14	$1.57	17.4 x
9/30/15	$1.34	20.3 x
12/31/15E	$1.40	19.5 x
12/31/16E	$1.70	16.0 x

Credit Ratings: Holding Co.

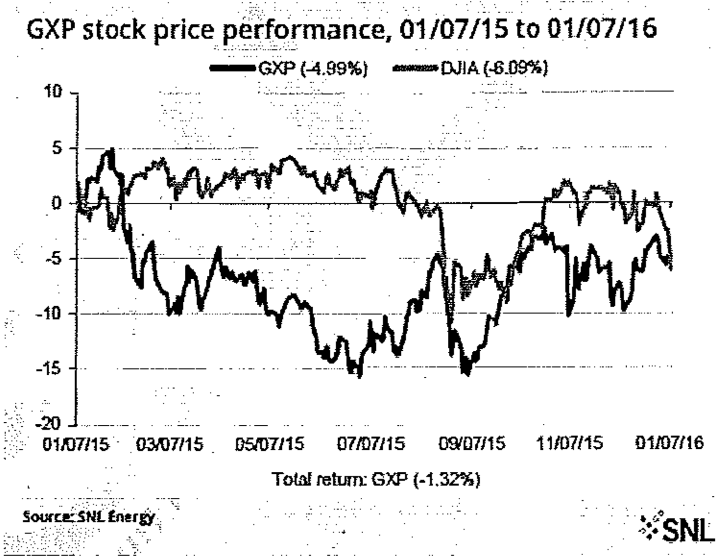
	Sr. Unsec	Long-term Issuer
S&P	BBB	BBB+
Moody's	Baa2	-
Fitch	-	-

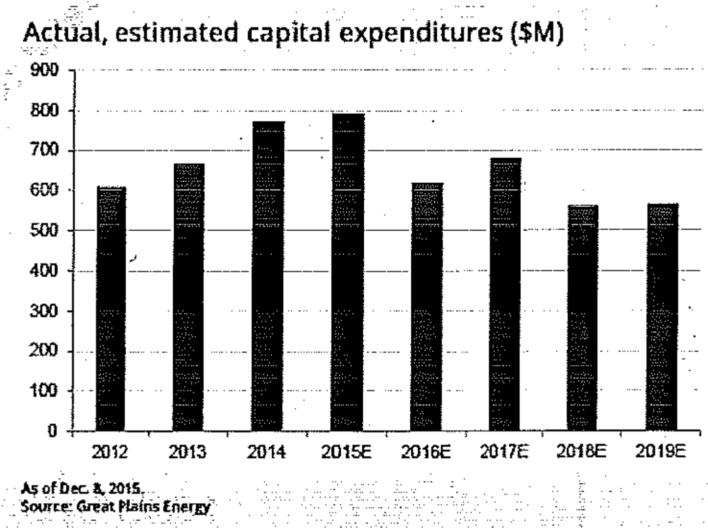
Dividend

Rate	Yield	Payout
$1.05	3.9%	78.4%

Summary

In the wake of the resolution of subsidiary Kansas City Power and Light's (KCP&L's) most recent round of rate cases (decided in September 2015), GXP expressed disappointment in the outcomes of those proceedings and, in general, with the regulatory paradigms (Missouri and Kansas) in which their electric utilities operate. Specifically, management was dissatisfied with the below average equity return authorizations in both jurisdictions, and with the Missouri Public Service Commission's (PSC's) continued opposition to/rejection of mechanisms designed to address the persistent regulatory lag faced by KCP&L and affiliate, KCP&L Greater Missouri Operations (GMO). GXP intends to work aggressively with other utilities to advocate for specific policy advancements and improve their regulatory frameworks. If these efforts are not successful, frequent rate case filings are likely. Most recently, the company has indicated that it is working with other stakeholders in Missouri on legislation that is expected to be introduced in the next few weeks.





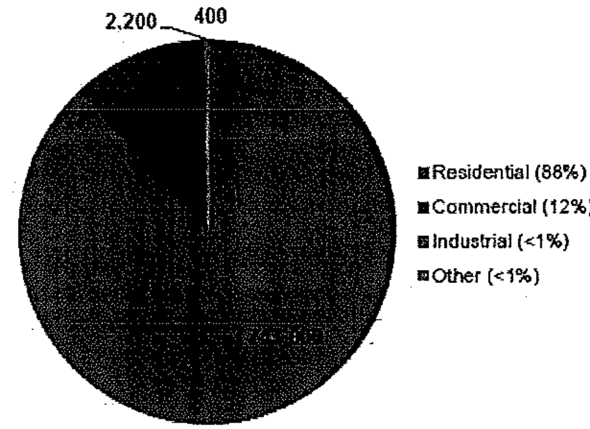
The past year was eventful for GXP, with the completion of KCP&L's environmental upgrades at the coal-fired La Cygne facility, co-owned equally with Westar Energy, at an estimated cost of $615 million. The La Cygne retrofits were in compliance with federal Best Available Retrofit Technology rules, commenced in 2011, were completed in March (Unit 2) and April 2015 (Unit 1), and were a primary driver of KCP&L's aforementioned rate cases. Also in 2015, KCP&L announced plans to cease burning coal at three facilities (Montrose, Sibley, and Lake Road) at various times between year-end 2016 and year-end 2021. In addition, the joint venture (JV) Transource Energy (TE, 13.5% owned by GXP, 86.5% owned by American Electric Power) placed one of its two transmission projects into service.

Despite operating in a favorable economic climate with low unemployment (4.4% versus the 4.9% September 2015 national average), sustained job growth (51 consecutive months) and customer growth

KM-R11

(18 consecutive quarters), and an encouraging real estate market (single-family residential permits through the first three quarters of 2015 were at an eight year high), weather-normalized sales through Sept. 30, 2015, were flat versus the comparable period in 2014. During the 2015 period, a 0.5% commercial sales increase was offset by declining sales to residential (0.2%) and industrial (1.2%) customers. Sales growth is expected to be flat to +0.5% for the full-year 2015, net of the anticipated impact of energy efficiency programs. Management stated that "the impact of our energy efficiency programs, new energy efficiency standards and population shifts to smaller homes and multifamily housing are driving lower average use per customer."

Retail electric utility customers
As of Sept. 30, 2015



Source: Great Plains Energy

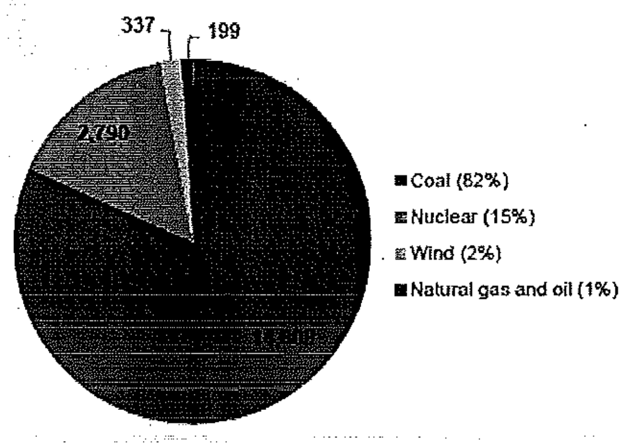
GXP's cap ex plan (2015-2019) calls for spending of nearly $3.2 billion, which should be a meaningful driver of earnings expansion for the next several years. However, near-term EPS are expected to contract from lower allowance for funds used during construction (AFUDC) earnings, increased expenses, and lower wholesale revenues.

GXP's stock price performance has been inconsistent over the last few years in comparison to the companies in the RRA Utility Index: the shares outperformed the group in 2013 (+19% versus +13%); underperformed in 2014 (+17% versus +25%); and, performed in line with the group's 4% decline in 2015. Based on our 2016 EPS estimate of $1.70, the GXP shares are trading at a 16x P/E multiple, a slight discount to the 16.6x group average, possibly due to investor uncertainty regarding management's projected 4%-6% earnings growth target.

Regulatory Environments

The Missouri regulatory environment, still traditionally regulated, has been relatively balanced from an investor perspective. However, recent PSC equity return authorizations (those that were not resolved by "black box" settlements) have been inconsistent, ranging from below to above the prevailing nationwide average (KCP&L was granted a slightly-below average 9.5% ROE in September 2015). For ratemaking purposes, test years in Missouri can be partially forecast at the time of filing, but are historical by the time a decision is rendered (limited "known-and-measurable" changes beyond the end of the test year may be recognized). Electric utilities are legally prohibited from including construction work in progress (CWIP) in rate base. KCP&L now has a fuel adjustment clause (FAC) in place that provides for the company to recover from/flow to ratepayers 95% of incremental variations in fuel and purchased power costs, net emissions allowances, and off-system sales (OSS) revenues from the levels included in base rates. A mechanism is in place for KCP&L that provides for recovery of demand-side management program-related costs and corresponding lost revenues (partial decoupling).

2015 net generation by fuel type (GWh)
Through Sept. 30



Source: Great Plains Energy

The Kansas regulatory environment, also traditionally structured, is relatively balanced from an investor viewpoint. Base rate proceedings in Kansas have generally been resolved via black box settlements; however, KCP&L's rate case decided in September 2015 was fully litigated, and the Kansas Corporation Commission (KCC) authorized a below average 9.3% ROE. Rates are determined using historical test periods, with certain changes to test-period data permitted. In addition, statutes permit the utilities to file "abbreviated" rate cases within 12 months of a KCC rate order. Kansas utilities have been permitted to include CWIP in rate base. An Energy Cost Adjustment clause is in place for KCP&L, through which it flows to ratepayers variations in OSS margins and fuel and purchased power costs. In addition, KCP&L has riders in place related to energy efficiency programs, transmission expense and cybersecurity expense.

Regarding renewables, in Missouri, investor-owned electric utilities were required to obtain at least 2% of their generation from renewables by 2011, with the threshold rising to 5% by 2014, to 10% by 2018, and to 15% by 2021. The electric utilities in Kansas were required to procure at least 10% of their generation from renewable resources beginning in 2011, with the threshold rising to 15% in 2016, and to 20% in 2020. In 2015, legislation was enacted that rendered the Kansas renewable standards voluntary. Renewable energy credits can be utilized in both jurisdictions.

Regulatory Update

Great Plains Energy -- Retail Base Rate Decisions (most recent by subsidiary and jurisdiction)							
Company	Juris.	Decision Date	Rate Change (millions)	ROR	ROE	Common Eq./ Total Capital	Rate Base (millions)
KCP&L	KS	9/10/2015	$40.1 [1,2]	7.44 %	9.30 %	50.48 %	$2,116.0
KCP&L	MO	9/2/2015	89.7 [1]	7.53	9.50	50.09	2,580.1
KCP&L GMO (MPS)	MO	1/9/2013	26.2 [3]	8.13	9.70	52.30	1,364.0
KCP&L GMO (L&P)	MO	1/9/2013	21.7 [3]	8.13	9.70	52.30	465.8

[1] Partial settlements were approved that did not address rate-of-return issues.

[2] After consideration of $14.9 million collected through a transmission rider and $6.4 million rolled into base rates from a property tax surcharge, the net ratepayer impact was a $48.6 million rate hike.

[3] Settled

Source: SNL Energy/Regulatory Research Associates

KCP&L--On Sept. 10, 2015, KCP&L's Kansas operations were authorized a $40.1 million electric base rate increase premised upon a below-industry-average 9.3% ROE. The KCC allowed the company to implement transmission and cybersecurity-related riders. We note that KCP&L is expected to file an abbreviated rate case with the KCC by November 2016 to address the company's share of the environmental projects at La Cygne not currently reflected in rates.

On Sept. 2, 2015, KCP&L's Missouri operations were authorized an $89.7 million increase based on a slightly below-average 9.5% ROE. The PSC allowed the company to implement an FAC, but rejected KCP&L's proposal to reflect certain Southwest Power Pool-related transmission costs in the FAC. Prior to the resolution of this case, KCP&L was the only electric utility in Missouri without an FAC. In addition, the PSC rejected KCP&L proposals to implement trackers related to property taxes and cybersecurity. The company appealed certain aspects of the decision to the Court of Appeals. The appeal is ongoing.

GMO--In 2013, the company's two Missouri service territories (MPS, L&P) were authorized, in aggregate, $47.9 million of rate increases premised upon a somewhat-below-average 9.7% ROE. GMO's request to implement a transmission rider was rejected by the PSC. GMO is expected to file new rate cases with the PSC in the first quarter of 2016.

Transmission Activity

Over the last few years, TE has been working on several transmission projects: a 175-mile, 345 KV line, targeted to be in service by year-end 2016 (TE's estimated cost, $266 million); and, a 30-mile, 345-KV line, placed into service in April 2015 at a cost of $65 million. We note that the Federal Energy Regulatory Commission (FERC) authorized these projects a 9.8% base ROE, and specified ROE premiums of 150 basis points and 50 basis points that are to apply to the 175-mile project and the 30-mile project, respectively. The FERC also authorized these projects to earn a cash return on CWIP.

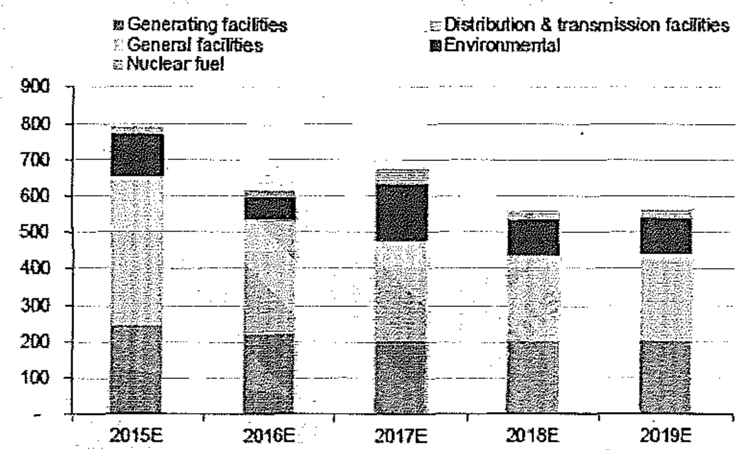
In a recent development, TE was selected by the PJM Interconnection to develop portions of the Thorofare Area Project, a 138-KV line to be built in West Virginia. Construction on the project is expected to begin in 2017, and conclude in 2019 (estimated cost, $60 million).

Earnings and Finances

GXP's earnings have been on a downward trend. EPS fell from $1.62 in 2013, to $1.57 in 2014, reflecting increased depreciation expense associated with capital additions, elevated operation and maintenance (O&M) expenses (including Wolf Creek expense), increased taxes, and the effects of unfavorable weather. These negative factors were partially offset by increased retail rates, the resolution of IRS tax issues, and lower interest expense. Through the first nine months of 2015, GXP's earnings were $1.22

compared with $1.44 in the comparable year-earlier period. The primary drivers of the decline were lower AFUDC earnings due to the completion of the La Cygne environmental projects, increased La Cygne-related depreciation and amortization expense, declines in wholesale revenues, lower earnings relative to the IRS tax issue resolution in 2014, and increased transmission expense. Partially offsetting these negatives were lower fuel and purchased power expense, reduced O&M expense, and increased retail rates in Kansas stemming from an abbreviated rate case resolved in 2014. (We note that, going forward, KCP&L's recently implemented FAC in Missouri is expected to largely mitigate the earnings variations from changes in wholesale power revenues.) For the full-year 2015, we expect EPS of $1.40, impacted by the recently completed KCP&L rate cases in Kansas and Missouri (new rates were effective late-September/early October), and within management's guidance range of $1.35 to $1.45 (previously $1.35 to $1.60). For 2016, we anticipate earnings of $1.70, driven primarily by the full-year impact of the KCP&L rate increases. We note that GXP is expected to release 2016 guidance in February.

Estimated capital expenditures breakout ($M)



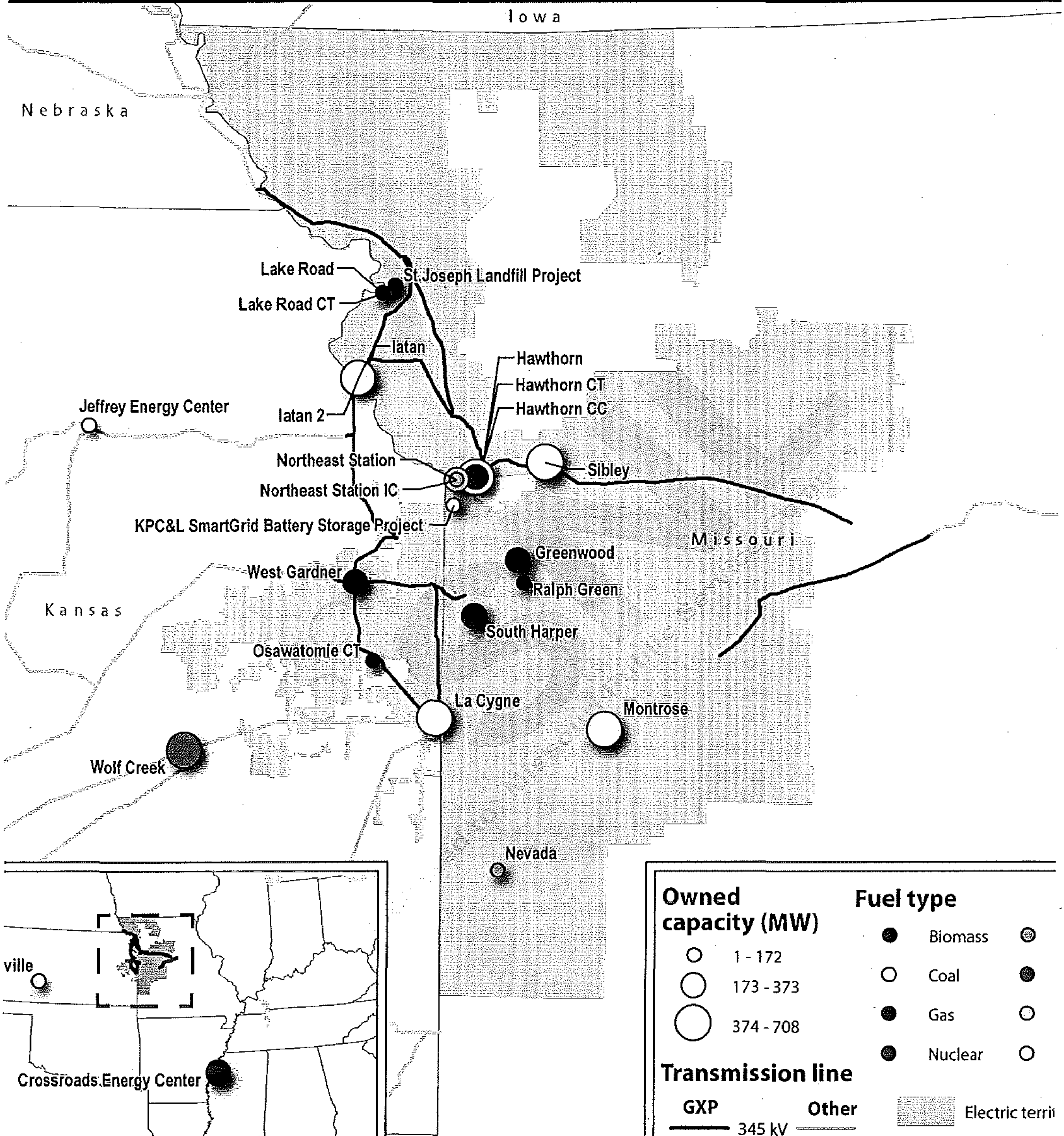
As of Dec. 8, 2015.
Source: Great Plains Energy

GXP's cap ex plan (excluding AFUDC) specifies spending of $3.2 billion over the next five years, with $793 million, $620 million, $680 million, $561 million, and $565 million projected for 2015, 2016, 2017, 2018, and 2019, respectively. About $1.1 billion is earmarked for transmission and distribution projects, and includes infrastructure replacement spending, service area expansion efforts, and vehicle fleet improvements. An additional nearly $1.1 billion is allocated to spending at generating facilities, including projects at Wolf Creek. Environmental spending of $543 million includes KCP&L's share of the La Cygne upgrades, and spending related to compliance with federal guidelines (Mercury and Air Toxic Standards rules, Coal Combustion Residuals rules, and proposed Clean Air Act/Clean Water Act rules). Other portions of the cap ex plan involve general facility spending (about $349 million), and nuclear fuel spending (roughly $130 million). We note that GXP's cap ex plan does not include spending at the TE JV.

GXP does not plan to issue new equity through 2017. The company's debt-to-total-capital ratio was 52.5% (as of Sept. 30, 2015), and its senior unsecured debt is rated Baa2/BBB by Moody's/Standard & Poor's. GXP has increased its dividend annually for the past five years, with the latest increase (7%) implemented in November 2015, exceeding management's stated 4% to 6% annual dividend growth target. The dividend payout ratio, 78%, is above both management's targeted long-term range of 60% to 70%, and the RRA Utility Index average of 63%. (Previous Report: 4/17/15)

Jim Davis
Tom Serzan

t Plains Energy Inc.



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Regulatory Research Associates

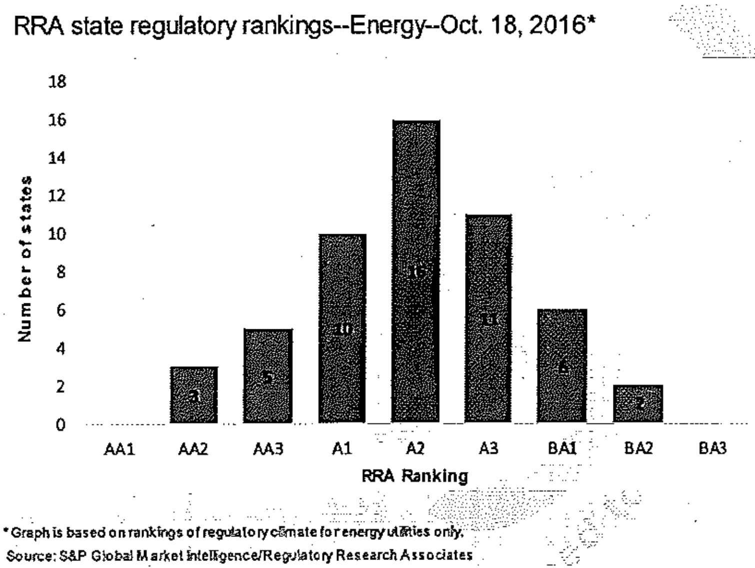
REGULATORY FOCUS

RRA is an offering of S&P Global Market Intelligence October 18, 2016

STATE REGULATORY EVALUATIONS
Regulatory Climate for Energy Utilities
~ Including an Overview of RRA's ranking process ~

Regulatory Research Associates, or RRA, evaluates the regulatory climates for ***energy utilities*** of the jurisdictions within the 50 states and the District of Columbia (a total of 53 jurisdictions) on an ongoing basis. The evaluations are assigned from an investor perspective and indicate the relative regulatory risk associated with the ownership of securities issued by each jurisdiction's electric and gas utilities. Each evaluation is based upon consideration of the numerous factors affecting the regulatory process in the state, and is changed as major events occur that cause RRA to modify its view of the regulatory risk accruing to the ownership of utility securities in that individual jurisdiction.

RRA also reviews evaluations when updating Commission Profiles, and when publishing this quarterly comparative report. The issues considered are discussed in Focus Notes, Commission Profiles, or Final Reports. RRA also considers information obtained from contacts with commission, company, and government personnel in the course of its research. The final evaluation is an assessment of the probable level and quality of the earnings to be realized by the state's utilities as a result of regulatory, legislative, and court actions.



RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more-constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less-constructive, higher-risk regulatory climate from an investor viewpoint.

Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position.

RRA attempts to maintain a "normal distribution" of the rankings, as seen in this chart that depicts the current distribution of the rankings.

(For a discussion of RRA's ratings process, see the Appendix that starts on page 3.)

RRA's previous "State Regulatory Evaluations" report was published on July 22, 2016, at which time RRA made two ranking changes: RRA lowered the ranking of the Alaska jurisdiction to Average/3 from Average/2; and, reduced the ranking of Hawaii regulation to Average/2 from Average/1.

While RRA is making no further changes at this time, certain jurisdictions bear some commentary. RRA is maintaining its Average/2 ranking of the Missouri jurisdiction at this time, but is that the 2016 legislative session concluded without action being taken on a bill that would have altered the state's ratemaking framework to address "regulatory lag." The issue is of particular concern to Missouri's electric utilities, and the matter is now being considered both by an interim legislative committee and the PSC. However, recent comments from the public counsel were dismissive of regulatory lag concerns. Should neither the legislature nor the PSC take action to address these issues, a reduction in the ranking may be justified.

In Nevada, Gov. Brian Sandoval recently appointed two new commissioners, declining to reappoint one commissioner whose term had expired and shifting another, whose term was not set to expire until 2017, to a different agency. This shake-up appears to be related to the commission's December 2015 decision modifying that state's net metering guidelines, something which has been controversial over the last couple of years. The 2015 decision led to backlash from various solar interests within the state. RRA accords Nevada regulation an Average/2 ranking.

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The tables below provide listings of RRA's rankings with respect to the **energy regulatory climate.**

	Above Average	**Average**	**Below Average**
1		California Colorado Kentucky Louisiana—PSC Louisiana—NOCC Michigan North Carolina North Dakota South Carolina Tennessee	District of Columbia Illinois Montana New Mexico Texas PUC West Virginia
2	Alabama Virginia Wisconsin	Arkansas Hawaii Idaho Kansas Maine Minnesota Missouri Nebraska Nevada New York Ohio Oklahoma Pennsylvania Utah Wyoming	Connecticut Maryland
3	Florida Georgia Indiana Iowa Mississippi	Alaska Arizona Delaware Massachusetts New Hampshire New Jersey Oregon Rhode Island South Dakota Texas RRC Vermont Washington	

ALPHABETICAL LISTING

Alabama - AA/2
Alaska – A/3
Arizona - A/3
Arkansas –A/2
California – A/1
Colorado - A/1
Connecticut – BA/2
Delaware – A/3
Dist. of Col. – BA/1
Florida – AA/3
Georgia – AA/3
Hawaii - A/2
Idaho - A/2
Illinois - BA/1
Indiana - AA/3
Iowa - AA/3
Kansas – A/2
Kentucky - A/1
Louisiana PSC – A/1
Louisiana NOCC—A/1
Maine - A/2
Maryland – BA/2
Massachusetts – A/3
Michigan - A/1
Minnesota - A/2
Mississippi - AA/3
Missouri - A/2
Montana - BA/1
Nebraska – A/2
Nevada – A/2
New Hampshire – A/3
New Jersey - A/3
New Mexico - BA/1
New York – A/2
North Carolina - A/1
North Dakota - A/1
Ohio - A/2
Oklahoma - A/2
Oregon - A/3
Pennsylvania - A/2
Rhode Island - A/3
South Carolina - A/1
South Dakota - A/3
Tennessee - A/1
Texas PUC - BA/1
Texas RRC – A/3
Utah - A/2
Vermont - A/3
Virginia - AA/2
Washington - A/3
West Virginia – BA/1
Wisconsin - AA/2
Wyoming - A/2

Appendix: Explanation of RRA ratings process

As noted above, RRA maintains three principal rating categories, Above Average, Average, and Below Average, with Above Average indicating a relatively more constructive, lower-risk regulatory environment from an investor viewpoint, and Below Average indicating a less constructive, higher-risk regulatory climate. Within the three principal rating categories, the numbers 1, 2, and 3 indicate relative position. The designation 1 indicates a stronger (more constructive) rating; 2, a mid-range rating; and, 3, a weaker (less constructive) rating within each higher-level category. Hence, if you were to assign numeric values to each of the nine resulting categories, with a "1" being the most constructive from an investor viewpoint and a "9" being the least constructive from an investor viewpoint, then Above Average/1 would be a "1" and Below Average/3 would be a "9."

The rankings are subjective and are intended to be comparative in nature. Consequently, RRA does not use a mathematical model to determine each state's ranking. However, RRA endeavors to maintain a "normal distribution" with an approximately equal number of rankings above and below the average. The variables that RRA considers in determining each state's ranking are largely the broad issues addressed in our State Regulatory Reviews/Commission Profiles and those that arise in the context of rate cases and are discussed in RRA Rate Case Final Reports. Keep in mind that the rankings reflect not only the decisions rendered by the state regulatory commission, but also take into account the impact of the actions taken by the governor, the legislature, the courts, and the consumer advocacy groups. The summaries below are intended to provide an overview of these variables and how each can impact a given regulatory environment.

Commissioner Selection Process/Membership--RRA looks at how commissioners are selected in each state. All else being equal, RRA attributes a greater level of investor risk to states in which commissioners are elected rather than appointed. Generally, energy regulatory issues are less politicized when they are not subject to debate in the context of an election. Realistically, a commissioner candidate who indicates sympathy for utilities and appears to be amenable to rate increases is not likely to be popular with the voting public. Of course, in recent years there have been some notable instances in which energy issues in appointed-commission states have become gubernatorial/senatorial election issues, with detrimental consequences for the utilities (e.g., Illinois, Florida, and Maryland, all of which were downgraded by RRA when increased politicization of the regulatory process became apparent.)

In addition, RRA looks at the commissioners themselves and their backgrounds. Experience in economics and finance and/or energy issues is generally seen as a positive sign. Previous employment by the commission or a consumer advocacy group is sometimes viewed as a negative indicator. In some instances, new commissioners have very little experience or exposure to utility issues, and in some respects, these individuals represent the highest level of risk, simply because there is no way to foresee what they will do or how long it will take them to "get up to speed."

Commission Staff/Consumer Interest--Most commissions have a staff that participates in rate proceedings. In some instances the Staff has a responsibility to represent the consumer interest and in others the Staff's statutory role is less defined. In addition, there may or may not be: additional state-level organizations that are charged with representing the interests of a certain class or classes of customers; private consortia that represent certain customer groups; and/or, large-volume customers that intervene directly in rate cases. Generally speaking, the greater the number of consumer intervenors, the greater the level of uncertainty for investors. The level of risk for investors also depends on the caliber and influence (political and otherwise) of the intervening parties and the level of contentiousness in the rate case process. RRA's opinion on these issues is largely based on past experience and observations.

Rate Case Timing/Interim Procedures--For each state commission, RRA considers whether there is a set time frame within which a rate case must be decided, the length of any such statutory time frame, the degree to which the commission adheres to that time frame, and whether interim increases are permitted. Generally speaking, RRA views a set time frame as preferable, as it provides a degree of certainty as to when any new revenue may begin to be collected. In addition, shorter time frames for a decision generally reduce the likelihood that the actual conditions during the first year the new rates will be in effect will vary markedly from the test period utilized (a discussion of test periods is provided below) to set new rates. In addition, the ability to implement all or a portion of a proposed rate increase on an interim basis prior to a final decision in a rate case is viewed as constructive.

Return on Equity--Return on equity (ROE) is perhaps the single most litigated issue in any rate case. There are two aspects RRA considers when evaluating an individual rate case and the overall regulatory environment: (1) how the authorized ROE compares to the average of returns authorized for energy utilities nationwide over the 12 months, or so, immediately preceding the decision; and, (2) whether the company has been accorded a reasonable opportunity to earn the authorized return in the first year of the new rates. (It is important to note that even if a utility is accorded a "reasonable opportunity" to earn its authorized ROE, there is no guarantee that the utility will do so.)

With regard to the first criteria, RRA looks at the ROEs historically authorized for utilities in a given state and compares them to utility industry averages (the benchmark statistics are available in *RRA's Major Rate Case Decisions Quarterly Updates*). Intuitively, authorized ROEs that meet or exceed the prevailing averages at the time established are viewed as more constructive than those that fall short of these averages.

With regard to the second consideration, in the context of a rate case, a utility may be authorized a relatively high ROE, but factors, e.g., capital structure changes, the age or "staleness" of the test period, rate base and expense disallowances, the manner in which the commission chooses to calculate test year revenue, and other adjustments, may render it unlikely that the company will earn the authorized return on a financial basis. Hence, the overall decision may be negative from an investor viewpoint, even though the authorized ROE is equal to or above the average. (RRA's *Rate Case Final Reports* provide a detailed analysis of each fully-litigated commission decision.)

Rate Base and Test Period--As noted above, a commission's policies regarding rate base and test year can impact the ability of a utility to earn its authorized ROE. These policies are often outlined in state statutes and the commission usually does not have much latitude with respect to these overall policies. With regard to rate base, commissions employ either a year-end or average valuation (some also use a date-certain). In general, assuming rate bases are rising, i.e., new investment is outpacing depreciation, a year-end valuation is preferable from an investor viewpoint. Again this relates to how well the parameters used to set rates reflect actual conditions that will exist during the rate-effective period; hence, the more recent the valuation, the more likely it is to approximate the actual level of rate base being employed to serve customers once the new rates are placed into effect. Some commissions permit post-test-year adjustments to rate base for "known and measurable" items, and, in general, this practice is beneficial to the utilities.

Another key consideration is whether state law and/or the commission generally permits the inclusion in rate base of construction work in progress (CWIP), i.e., assets that are not yet, but ultimately will be, operational in serving customers. Generally, investors view inclusion of CWIP in rate base for a cash return as constructive, since it helps to maintain cash flow metrics during a large construction phase. Alternatively, the utilities accrue allowance for funds used during construction (AFUDC), which is essentially booking a return on the construction investment as a regulatory asset that is recoverable from ratepayers once the project in question becomes operational. While this method bolsters earnings, it does not augment cash flow.

With regard to test periods, there are a number of different practices employed, with the extremes being fully-forecasted (most constructive) on the one hand and fully historical (least constructive) on the other. Some states utilize a combination of the two, in which a utility is permitted to file a rate case that is based on data that is fully or partially forecast at the time of filing, and is later updated to reflect actual data that becomes known during the course of the proceeding.

Accounting--RRA looks at whether a state commission has permitted unique or innovative accounting practices designed to bolster earnings. Such treatment may be approved in response to extraordinary events such as storms, or for volatile expenses such as pension costs. Generally, such treatment involves deferral of expenditures that exceed the level of such costs reflected in base rates. In some instances the commission may approve an accounting adjustment to temporarily bolster certain financial metrics during the construction of new generation capacity. From time-to-time commissions have approved frameworks under which companies were permitted to, at their own discretion, adjust depreciation in order to mitigate under-earnings or eliminate an over-earnings situation without reducing rates. These types of practices are generally considered to be constructive from an investor viewpoint.

Alternative Regulation--Generally, RRA views as constructive the adoption of alternative regulation plans that: allow a company or companies to retain a portion of cost savings (e.g. fuel, purchased power, pension, etc.) versus benchmark levels; permit a company to retain for shareholders a portion of off-system sales revenues; or, provide a company an enhanced ROE for achieving operational performance and/or customer service metrics or for investing in certain types of projects (e.g., demand-side management programs, renewable resources, new traditional plant investment). The use of ROE-based earnings sharing plans is, for the most part, considered to be constructive, but it depends upon the level of the ROE benchmarks specified in the plan, and whether there is symmetrical sharing of earnings outside the specified range.

Court Actions--This aspect of state regulation is particularly difficult to evaluate. Common sense would dictate that a court action that overturns restrictive commission rulings is a positive. However, the tendency for commission rulings to come before the courts, and for extensive litigation as appeals go through several layers of court review, may add an untenable degree of uncertainty to the regulatory process. Also, similar to commissioners, RRA looks at whether judges are appointed or elected.

Legislation--While *RRA's Commission Profiles* provide statistics regarding the make-up of each state legislature, RRA has not found there to be any specific correlation between the quality of energy legislation enacted and which political party controls the legislature. Of course, in a situation where the governor and legislature are of the same political party, generally speaking, it is easier for the governor to implement key policy initiatives, which may or may not be focused on energy issues. Key considerations with respect to legislation include: how prescriptive newly enacted laws are; whether the bill is clear or ambiguous and open to varied interpretations; whether it balances ratepayer and shareholder interests rather than merely "protecting" the consumer; and, whether the legislation takes a long-term view or is it a "knee-jerk" reaction to a specific set of circumstances.

Corporate Governance--This term generally refers to a commission's ability to intervene in a utility's financial decision-making process through required pre-approval of all securities issuances, limitations on leverage in utility capital structures, dividend payout limitations, ring-fencing, and authority over mergers (discussed below). Corporate governance may also include oversight of affiliate transactions. In general, RRA views a modest level of corporate governance provisions to be the norm, and in some circumstances these provisions (such as ring-fencing) have protected utility investors as well as ratepayers. However, a degree of oversight that would allow the commission to "micromanage" the utility's operations and limit the company's financial flexibility would be viewed as restrictive.

Merger Activity--In cases where the state commission has authority over mergers, RRA reviews the conditions, if any, placed on the commission's approval of these transactions, specifically: whether the company will be permitted to retain a portion of any merger-related cost savings; if guaranteed rate reductions or credits were required; whether certain assets were required to be divested; and, whether the commission placed stringent limitations on capital structure and/or dividend policy.

Electric Regulatory Reform/Industry Restructuring--RRA generally does not view a state's decision to implement retail competition as either positive or negative from an investor viewpoint. However, for those states that have implemented retail competition, RRA considers: whether up-front guaranteed rate reductions were required; how stranded costs were quantified and whether the utilities were accorded a reasonable opportunity to recover stranded costs; the length of the transition period and whether utilities were at risk for power price fluctuations associated with their default service responsibilities during the transition period; how default service is procured following the end of the transition period; and, how any price volatility issues that arose as the transition period expired were addressed.

Gas Regulatory Reform/Industry Restructuring--Retail competition for gas supply is more widespread than is electric retail competition, and the transition was far less contentious, as the magnitude of potential stranded asset costs was much smaller. Similar to the electric retail competition, RRA generally does not view a state's decision to implement retail competition for gas service as either positive or negative from an investor viewpoint. RRA primarily considers the manner in which stranded costs were addressed and how default service obligation-related costs are recovered.

Securitization--Securitization refers to the issuance of bonds backed by a specific existing revenue stream that has been "guaranteed" by regulators. State commissions have used securitization to allow utilities to recover demand-side management costs, electric-restructuring-related stranded costs, environmental compliance costs, and storm costs. RRA views the use of this mechanism as generally constructive from an investor viewpoint, as it virtually eliminates the recovery risk for the utility.

Adjustment Clauses--For many years adjustment clauses have been widely utilized to allow utilities to recover fuel and purchased power costs outside a general rate case, as these costs are generally subject to a high degree of variability. In some instances a base amount is reflected in base rates, with the clause used to reflect variations from the base level, and in others, the entire annual fuel/purchased power cost amount is reflected in the clause. More recently, the types of costs recovered through these mechanisms has been expanded in some jurisdictions to include such items as pension and healthcare costs, demand-side management program costs, FERC-approved transmission costs, and new generation plant investment. Generally, RRA views the use of these types of mechanisms as constructive, but also looks at the frequency with which the adjustments occur, whether there is a true-up mechanism, and whether adjustments are forward-looking in nature. Other mechanisms that RRA views as constructive are weather normalization clauses that are designed to remove the impact of weather on a utility's revenue and decoupling mechanisms that may remove not only the impact of weather, but also the earnings impacts of customer participation in energy efficiency programs. Generally, an adjustment mechanism would be viewed as less constructive if there are provisions that limit the utility's ability to fully implement revenue requirement changes under certain circumstances, e.g., if the utility is earning in excess of its authorized return.

Integrated Resource Planning--RRA generally considers the existence of a resource planning process as constructive from an investor viewpoint, as it may provide the utility at least some measure of protection from hindsight prudence reviews of its resource acquisition decisions. In some cases, the process may also provide for pre-approval of the ratemaking parameters and/or a specific cost for the new facility. RRA views these types of provisions as constructive, as the utility can make more informed decisions as to whether it will proceed with a proposed project.

Renewable Energy/Emissions Requirements--As with retail competition, RRA does not take a stand as to whether the existence of renewable portfolio standards or an emissions reduction mandate is positive or negative from an investor viewpoint. However, RRA considers whether there is a defined pre-approval and/or cost-recovery mechanism for investments in projects designed to comply with these standards. RRA also reviews whether there is a mechanism (e.g., a percent rate increase cap) that ensures that meeting the standards does not impede the utility's ability to pursue other investments and/or recover increased costs related to other facets of its business. RRA also looks at whether incentives, such as an enhanced ROE, are available for these types of projects.

Rate Structure--RRA looks at whether there are economic development or load-retention rate structures in place, and if so, how any associated revenue shortfall is recovered. RRA also looks at whether there have been steps taken over recent years to reduce/eliminate inter-class rate subsidies, i.e., equalize rates of return across customer classes. In addition, RRA considers whether the commission has adopted or moved towards a straight-fixed-variable rate design, under which a greater portion (or all) of a company's fixed costs are recovered through the monthly customer charge, thus according the utility greater certainty of recovering its fixed costs.

For a full list of Regulatory Focus and Financial Focus reports, go to the SNL Research Library.

Lillian Federico
Sara May Bellizzi
Jim Davis
Russell Ernst
Lisa Fontanella
Monica Hlinka
Dennis Sperduto