Exhibit No.:	
Issue:	Regulatory Mechanisms
Witness:	H. Edwin Overcast
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2014-0370
Date Testimony Prepared:	May 7, 2015

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

REBUTTAL TESTIMONY

OF

H. EDWIN OVERCAST

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
May 2015

REBUTTAL TESTIMONY

OF

H. EDWIN OVERCAST

Case No. ER-2014-0370

I. Introduction

Q. Please state your name and business address.

A. My name is H. Edwin Overcast, Director, Management Consulting, Black & Veatch Corporation, POB 2946, McDonough, GA 30253.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this rebuttal testimony ("Rebuttal Testimony") before the Missouri Public Service Commission ("Commission") on behalf of Kansas City Power & Light Company ("KCP&L" or the "Company").

Q. Please describe your education, experience and employment history.

A. A detailed summary of my educational and professional experience is provided in Schedule HEO-1 to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. I have been employed in the energy industry for over 40 years in various rate, regulatory and planning positions. My industry employers include: the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. My testimony has addressed a variety of issues including cost allocation, rate design, regulatory policy, open access and unbundling, bypass economics, forecasting, electric marginal costs, and a number of other issues. In addition, I have been a lecturer in a number of energy industry sponsored training programs including: the Edison Electric Institute Rate Fundamentals Course and the Advanced Rate Course; the American Gas Association Rate Course and the Advanced Rate School; and the Southern Gas Association Intermediate Rate Course. Specifically, I have lectured on the principles of electric cost of service for both retail and wholesale jurisdictions.

Q. Have you previously testified in a proceeding before the Missouri Public Service Commission ("Commission" or "MPSC") or before any other utility regulatory agency?

A. Yes. I have testified before the Commission on a number of occasions for The Empire District Electric Company on matters related to cost of service, rate design and regulatory policy including testimony related to the fuel adjustment clause. I have also testified in Kansas, Connecticut, Massachusetts, Georgia, Tennessee, Montana, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board, The Régie de L'énergie and the British Columbia Utilities Commission. In my career, I have testified on issues related to the use of various regulatory mechanisms, including rate adjustment mechanisms (RAMs), formula rates and policy considerations designed to provide utilities a reasonable opportunity to achieve its Commission-authorized return while protecting customers from paying higher than actual costs.

Q. What is the purpose of your Rebuttal testimony?

A. In response to the direct testimony of Michael Brosch on behalf of Midwest Energy Consumers Group ("MECG"), Lena Mantle on behalf of the Office of Public Counsel (OPC) and the Commission Staff, there are several purposes for my testimony as follows:

1. Discuss the theory behind the use of regulatory mechanisms, including RAMs as a tool for inclusion in just and reasonable utility rates as a backdrop for my responding to the specific issues raised by other parties in this proceeding related to KCP&L's regulatory mechanism proposals;
2. Discuss the role of deferred accounting treatment as a tool for matching costs and revenues and how that differs from a RAM and may even be a part of a RAM;
3. Discuss the role of an Accounting Authority Order (AAO) and how it differs from both a RAM and deferred accounting treatment;
4. Discuss the utility rate principles that support the use of a full tracking Fuel and Purchase Power Adjustment Clause (FAC) as a RAM for KCP&L;
5. Review the rationale for deferred accounting treatment related to KCP&L's proposed trackers for Vegetation Management, Property Tax and Critical Infrastructure Protection ("CIP") and Cyber Security;
6. Respond to the specific issues raised by other parties in this proceeding as they relate to KCP&L's proposed regulatory mechanisms; and
7. Discuss the report prepared by Black & Veatch (which accompanies my rebuttal testimony) to explain in detail the roles of various regulatory mechanisms, including RAMs, trackers and other regulatory tools used by utility regulators to achieve the

necessary balance in the regulatory compact to align the interests of the utilities' customers and shareholders.

Q. How is your rebuttal testimony organized?

A. My rebuttal testimony is organized into the following sections:

I. Introduction

II. Ratemaking Tools

III. Fuel and Purchased Power Adjustment Clause

IV. Trackers

V. Summary and Conclusions

Q. Please summarize your conclusions and recommendations.

A. Based on my review of the specific issues raised by other parties in this proceeding as they relate to the KCP&L's proposed regulatory mechanisms, I have reached the following findings and recommendations:

1. I conclude that KCP&L's full tracking FAC proposal should be adopted by the Commission to ensure the implementation of just and reasonable rates for KCP&L. This action will align the interests of KCP&L's customers and shareholders by providing KCP&L with a reasonable opportunity to earn its Commission authorized-return while setting customer rates that recover only prudently incurred expenses.
2. There is no basis for any arbitrary disallowance of KCP&L's fuel costs as a so-called incentive mechanism since there are other real incentives that are not based on the presumption that the fuel clause results in management behaviors that cannot be assumed, but must be proved.

3. I also conclude that each of the three trackers proposed by KCP&L should be approved. The tracker treatment proposed by KCP&L is a conservative approach relative to the RAMs used in other jurisdictions by comparable utilities. KCP&L's proposal provides for a balancing of interest and benefits for the long-run interests of all stakeholders in a more efficient regulatory process.
4. The FAC and trackers as proposed by KCP&L will allow the Company to recover its prudently incurred costs for the items covered while protecting customers from over-paying for such costs and, consequently, do not provide for any unjust rate of return for its shareholders or any penalties resulting from the denial of cost recovery for costs that were prudently incurred. As such, these proposals satisfy the legal constraints imposed on regulation by statute and court decisions; the constraint of equitable treatment of the customer and investor interests; and the public interest standard.

II. Ratemaking Tools

Q. What do you mean when you say ratemaking tools?

A. In order to respond to the testimony of other parties it is necessary to begin by carefully distinguishing the different features of the types of tools available for the Commission to use in providing KCP&L a reasonable opportunity to achieve its Commission-authorized return. Unfortunately, the confusion related to various tools is part and parcel to the arguments raised related to the FAC and trackers proposed by KCP&L. These ratemaking tools include three distinctly different types of tools: RAMs (the FAC is an example), trackers and Accounting Authority Orders ("AAO"). KCP&L has not requested an AAO in this case and the typical request for an AAO occurs unrelated to a rate case proceeding while both a RAM and trackers are most frequently requested as part of a rate case.

Obviously, there are other ratemaking tools that go beyond those discussed above. For a more detailed discussion of these and other tools Black& Veatch prepared a report "Modernizing Utility Ratemaking Practices in a Changing Industry" that is attached as Schedule HEO-2 to this testimony. That report was prepared at the request of KCP&L to provide industry context including theory and practice related to addressing the types of issues utilities are facing and the potential solutions available to KCP&L. As appropriate, my testimony will refer to the report for more detailed discussion of certain issues where the contextual background is critical in responding to the testimony of other parties.

Q. Please explain the concept of a RAM as it relates to the KCP&L FAC proposal.

A. A RAM is a rate adjustment mechanism that is determined in the context of rate case. The rate case establishes a formula for certain identified costs, in whole or in part, to change periodically so that actual costs match actual rates and recovery of those costs. The RAM becomes a part of each rate schedule to which it is applicable. The KCP&L proposed FAC is an adjustment mechanism that recovers or credits changes in the costs defined under the clause above or below a base value set in the rate case. Those costs above or below the base costs are presumed to be prudent subject to future audit to assure that only properly incurred costs are included and that those costs were indeed prudent. If the costs recovered are greater than the determined prudent amount after a hearing related to the questioned costs, consumers would receive a refund of the amount determined to be imprudent plus interest. Essentially the FAC is a formula rate that becomes part of every rate schedule. That formula is defined in detail and is consistent with the approved revenue requirements included in base rates to assure that there is no over-recovery or under-recovery of the just and reasonable level of revenue requirements. The development of the formula for the type of FAC proposed by KCP&L is discussed in detail in "Modernizing Utility Ratemaking Practices in a Changing Industry" under the heading "Other Types of Adjustment Clauses" page 16 and following. As this formula illustrates, the difference between the base costs used to set the rates and revenue requirements as approved by the Commission are subject to an FAC amount calculated so that the base amount plus the FAC amount matches the fuel costs and fuel related revenues subject to a true-up adjustment dollar for dollar. As a result of this treatment, the expenses associated with the FAC have no impact on the utility earnings either positive or negative. Where these costs, in total and on a per kWh basis, are volatile[1] the matching principle results in more efficient rates that are symmetrically just and reasonable for customers and shareholders. Since this FAC has no impact on earnings regardless of the accuracy of the base fuel cost forecast or the actual fuel costs resulting from market forces beyond the control of utility management, there is no impact on the opportunity to earn the Commission-authorized return with an FAC. Without the FAC, the utility is denied a reasonable opportunity to earn its allowed return when fuel costs rise and customers pay rates that produce in excess of the allowed return when fuel costs fall relative to base costs of fuel used in the test year.

[1] Volatile costs mean changing or not amenable to estimation based on historic information. The context of volatile differs from the concepts such as extreme or extraordinary.

Q. Please explain the concept of a tracker as that mechanism is used in Missouri.

A. A tracker is fundamentally different from a RAM because it does not adjust rates between rate cases. Rather, the tracker is an accounting tool that permits the utility to identify the difference between a base cost determined in a rate case and the actual costs occurring in a subsequent period. That difference in base and actual costs is recorded on the utility's books as an asset if costs are higher or a liability if costs are lower. The fact that it is recorded as an asset or a liability on the balance sheet means that any difference has no impact on the income statement in the period incurred. Without the tracker, KCP&L receives either a windfall gain when costs for the test year are estimated to be higher than actual costs or suffers a loss of prudently incurred costs when the test year estimate is lower than the actual costs. In either event there is a mismatch between the authorized level of return and the actual return in the Rate Year without trackers. The tracker also means that as to those costs included in the tracker the treatment is symmetric for customers and shareholders. Any accumulated balance in the asset or liability account for this expense (including interest) is not subject to recovery until the next rate case when the utility files to amortize the value of the account balance. At that time, the Commission and other parties review the prudence of the expense and any other circumstances that may be deemed relevant to determine the amount, if any, to be amortized in rates. The amortization is prospective and actual revenues match actual costs subject to a final reconciliation.

Q. What is an AAO and how does it differ from either a RAM or a tracker?

A. An AAO is a completely different type of mechanism as compared to a RAM or a tracker. Most often an AAO is sought to recover a significant, unexpected and unforeseeable expense outside of the confines of a rate case. Typically the costs have not been included in the revenue requirement of the utility because the event that causes these costs is an event completely outside the control of the utility such as a major weather event like an ice storm, a major flood or other natural disaster. These costs must be approved in a separate review for the utility to defer the costs of restoring service under emergency conditions and incurring a level of costs unrelated to the cost of normal operations. The nature of these costs is such that they would never be adequately included in rates under the test year concept simply because they are not normal costs for any test year. These costs are deferred for later review and amortization through a rate case or even a separate hearing.

Q. Please summarize the regulatory processes involved in a RAM, a tracker and an AAO.

A. Both a RAM and a tracker are established as part of a rate case. It is unlikely that an AAO would be established as part of a rate case. A RAM becomes part of each rate schedule to which it applies, tracks costs in total or deviations from a base amount and flows those cost through to customers as those costs change subject to an audit review to assure compliance with the formulaic process approved for the RAM and a determination that the costs recovered were prudently incurred. A tracker establishes a base amount in a rate case and tracks differences between the base amount and the actual amount during the period the rates are effective. The differences are recorded as either a regulatory asset or liability for review in the next rate case. These differences are only collected after full rate case review for compliance with the accounting procedures required by the tracker and for prudence. If approved by the Commission those costs are amortized in rates in a subsequent period. Finally, an AAO is neither a tracker nor a RAM. It is an affirmative approval by the Commission that allows the utility to defer costs incurred as the result of some unexpected and uncontrollable event not adequately reflected in current rates for later review and amortization. The review standards for recovery of an AAO are the same as for a RAM or a tracker.

Q. Is the definition of each concept critical to any assessment of the KCP&L proposals?

A. Yes. KCP&L is only proposing one RAM – the FAC – and the other adjustments are tracker proposals. No AAO has been proposed in this case by KCP&L.

III. The Fuel Adjustment Clause

Q. Have you reviewed the proposed FAC submitted to the Commission by KCP&L?

A. Yes. I have reviewed the FAC as filed.

Q. Have you reviewed the testimony supporting the filing?

A. Yes. I have reviewed the KCP&L testimony filed in support of the FAC.

Q. Have you reviewed the testimony of the other parties related to the FAC filing?

A. Yes. I have reviewed the testimony filed by other parties relative to the proposed FAC.

Q. Please provide an overview of your comments related to the testimony of other parties related to the proposed FAC.

A. At a high level, the other parties either oppose approval of the FAC on various grounds or they propose that if the FAC is approved the proposal should be modified in a variety of ways. In general the opposition to the FAC is based on philosophical views that create opposition through misplaced, incomplete or invalid analysis of both the FAC proposal and the fundamental requirement that rates approved in this case are required to provide KCP&L a reasonable opportunity to achieve its Commission-authorized return.

Q. Please explain why the absence of an FAC does not provide the utility a reasonable opportunity to achieve its Commission authorized return.

A. In simplest terms, the base cost of fuel in rates is a forecast that, like all other forecasts, is subject to forecast error. The magnitude of the forecast error is significant because costs are no longer determined solely by the utility's own load dispatch due to the new SPP Integrated Market (IM). While participation in the new Southwest Power Pool, Inc. ("SPP") IM may result in a more rational and orderly market, it does not remove the underlying volatility of fuel costs for KCP&L. The combination of variables that are the basis for estimating fuel costs are so numerous and interrelated that any estimate of fuel costs based on circumstances today will be unlikely to occur in the Rate Year. Critical variables include the delivered cost of various fuel inputs, the availability and operating characteristics of the KCP&L generation fleet (including heat rate curves, load, ambient temperature, unit availability, partial deratings, and seasonal deratings, to name a few factors). The ambient temperature has an impact on the price of inputs and, unit operations. The natural gas market is particularly sensitive to temperature as we have observed historically. For KCP&L, this means that its forecast of actual costs for its customers is a function of many factors that KCP&L does not control and cannot adequately be estimated in an unbiased way resulting in an almost certain mismatch in costs and revenues in the rate year. As a low cost provider in SPP, the operation of the KCP&L generation fleet will be changed. Its baseload coal and nuclear units will run continuously regardless of its own load and the value of those added running hours will vary based on unit availability at the margin and the impact of nodal pricing. At this time, there is no practical way to evaluate the extent of ramping for coal units associated with operation in SPP. Nodal pricing in other Regional Transmission Organizations (RTO) and Independent System Operators (ISO) markets is highly variable on an hourly basis. The hourly variation is driven by a number of variables such as weather, congestion on transmission paths, dispatch limitations such as environmental rules and operating constraints, unit deratings by season, composite heat rate curves and so forth. Day ahead hourly prices will vary from real time prices adding an element of additional variability to the expected net fuel costs. Fuel costs may also be volatile even if fuel prices themselves do not change as a result of different unit commitments based on the level of generation from wind, solar and hydro power facilities, weather conditions and other operating issues.

Q. Please summarize the intervenors' opposition to the FAC.

A. There are two different types of opposition. First, there is opposition related to terms of a settlement agreement. Since I was not a party to that agreement, I will not address that issue. The second opposition argument is that KCP&L has not proved the need for FAC based on volatility of fuel and purchased power costs and the impact of the absence of an FAC on the Company. I will focus on this latter argument. In addition, other parties have made recommendations related to fuel cost recovery if a clause is approved and I will address those issues as well.

Q. Please discuss the testimony of MECG witness Brosch as it relates to the standards for approval.

A. Witness Brosch begins by citing the three criteria the Commission has adopted to determine if an FAC should be adopted. Those three criteria are as follows:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels; and
3. Volatile in amount, causing significant swings in income and cash flows if not tracked.

Witness Brosch continues by expanding the definition based on a decision by the Commission that broadens the concept of volatility to include that volatility is not merely that prices increase but that they should both increase and decrease[2]. I will discuss this view proffered by the Commission subsequently. Witness Brosch proceeds to express his views about the determination of the revenue requirements for a utility based on rate case treatment of costs that will change from the test year to the Rate Effective Period[3]. Witness Brosch states "Cost tracking mechanisms should be approved only in instances where compelling circumstances justify departure from traditional test period review of all test year costs and revenues within rate case proceedings in which the overall revenue requirement can be audited and considered in a balanced and synchronized manner."

This view of the ratemaking process is not consistent with the Supreme Court requirement that the Commission rate order must provide the utility a reasonable opportunity to earn the allowed return, a fact that Witness Brosch seems to ignore in his concept of a "traditional test year" and a "balanced and synchronized" review. To be clear, the test year concept is about making a reasonable estimate of the prudent costs and

[2] It should be noted that the Commission subsequently disavowed this added provision when it recognized that systematic increases in fuel and purchased power costs were a reason that utilities actually needed an FAC to have a reasonable opportunity to earn the allowed return. Report and Order, Case No. ER-2008-0318, p. 67.

revenues likely to occur during the rate effective period. Any other definition of a test period is inconsistent with providing a reasonable opportunity for the utility to actually achieve its Commission-authorized return. That "balanced and synchronized" view of costs must recognize that if expenses are prudent they must be included in the estimated revenue requirements, or addressed in some other way, otherwise there is no opportunity for the utility to achieve its Commission-authorized return. Witness Brosch conveniently ignores the fact that if costs are expected to be higher in the rate year those higher costs must be reflected in rates, or otherwise accounted for, in order to maintain an appropriate matching of costs and revenues. In the Hope Natural Gas decision, the Supreme Court is unequivocal in stating that "it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business." Thus to ignore that the test year understates the cost of fuel and purchased power as an expense in comparison to the actual costs incurred during the rate effective period would not be permitted under the Hope criteria as doing so does not balance the interests of consumers and shareholders. Further, there is also a possibility that circumstances might result in a lower cost for KCP&L and it is reasonable that the symmetric fuel adjustment clause allow customers the full benefit of lower FAC costs.

Q. Please comment on the discussion by witness Brosch related to the Commission's prior and now reversed view that if costs are only increasing an FAC is not warranted.

A. In addition to the Supreme Court's Hope standard noted above, the decision in Missouri *ex rel.* Southwestern Bell Tel. Co. v. Public Service Commission establishes a

[3] The Rate Effective Period is the first twelve months after new rate take affect and is also referred to as the Rate Year.

fundamental tenet of rate regulation that rates must create an opportunity for the utility to earn the allowed return. In that case Justice Brandeis concluded that a utility is permitted an *opportunity to earn the cost of service including a return of and on the assets devoted to public service*.[4] (Emphasis added). The concept of cost of service includes the prudently incurred costs of fuel and purchased power being discussed here. This regulatory principle is well accepted and has a long history of application. As such if the Commission knows that costs during the rate effective period are likely to differ – either higher or lower[5] - above or below the level approved in rates and that those costs are beyond the reasonable control of utility management, there is no justification for disallowing matching of those actual costs through the FAC as part of the formula rate for determining the revenue requirements of the Company. The Commission should clearly state that the approval of the FAC meets the just and reasonable standard even if the costs are only increasing consistent with these two Supreme Court decisions. Further, the FAC results in dollar for dollar matching of the expense and revenue related to the fuel and purchased power costs in the Rate Effective Period, protecting the interests of both customers and shareholders.

Q. Does this matching of fuel costs change the incentives provided by regulatory lag?

A. No, although this is a common misconception related to the role of regulatory lag related to incentives. I will discuss FAC incentives particularly at a later point in my testimony when I discuss proposals by other parties related to the FAC. At this point, witness Brosch quotes the Commission related to the good effect of regulatory lag as it relates to

---

[4] Missouri ex rel. Southwestern Bell Tel. Co. v. Public Service Commission, 262 U. S. 276, 290-291 (1923).

[5] Essentially this concept relies not on the test year level but on the uncertainty and inability to determine with any accuracy the expected total expenses for the costs in question, the costs should be determined through the operation of an FAC in the Rate Effective Period.

efficiency and then concludes that an FAC destroys "any incentive for management efficiency and aggressive cost reduction that otherwise results from regulatory lag." The position expressed in this testimony is incorrect not only as it relates to the FAC as I discuss below but more importantly as it relates to all other expenses and capital costs for KCP&L. As witness Brosch points out in his testimony base fuel costs represent only 23 percent of overall expenses. That means that the regulatory lag incentive remains fully operational for 77% of the other expenses if we ignore for the moment the tracker effects which in total would be a smaller portion of expense than the base fuel and purchased power costs. Thus, the FAC cannot and does not destroy any incentive for efficiency as stated by witness Brosch. Efficient operation of KCP&L remains a fiduciary objective for management as it relates to expenses, capital investment and even to the FAC costs.

Q. MECG witness Brosch begins his review of the FAC by arguing that the costs for individual components of the proposed FAC are only significant relative to the total cost and not to changes in expected costs. Please comment on the analysis of the significance of these costs to the Company.

A. Witness Brosch has constructed his significance analysis on the wrong variables. It is not the significance of the costs or even the change in costs relative to the operating expenses or total revenues that measures the importance of the FAC, or even complies with the material impact standard as it relates to the financial performance of the utility during the Rate Effective Period. The relevant variable is the impact of changes in the fuel and purchased power costs as defined by KCP&L as it relates to dollars available for equity return. A good example relates to the analysis of coal costs where witness Brosch measures the impact of a 10% increase in the cost of coal at a $2.1 million level which is compared to total operating costs and total revenue. Witness Brosch continues on this theme by citing the $4 million dollar increase in fuel and purchased power costs from Mr. Rush's testimony and concludes that number is also inconsequential relative to total expenses and revenues and no basis for approval of an FAC. The fundamental problem is that the level of revenue requirement or the level of operating expense is not relevant to the financial performance that must be assessed to determine the need for an FAC. The correct comparison is how much $2.1 million or $4 million impacts the ability of KCP&L to achieve its Commission-authorized return. Since the earned return on equity is a residual after all operating expenses and debt payments have been made it becomes clear that the Supreme Court admonition in Hope and Justice Brandeis in Southwestern Bell related to recovery of expenses is fundamental to earning the allowed return. The Commission itself recognizes this point when it concludes "In a sense, the need to provide a utility with a sufficient opportunity to earn a fair return on equity is just a summation of the end goal of the previously described three-part test."[6] Witness Brosch's whole analysis is based on a flawed standard of review relative to the financial impact of the absence of an FAC.

Q. Has witness Brosch relied on a Commission decision related to the denial of an FAC that has been superseded by a later decision?

A. Yes. In his opening remarks witness Brosch relies on the Report and Order, May 22, 2007, Union Electric Company d/b/a Ameren Missouri, Case No. ER-2007- 0002, pages 17-19. In that order, the Commission rejected the proposed FAC based on much of the same arguments raised by witness Brosch related to the cost of coal and nuclear fuel and the upward trend in those prices. As noted above, the subsequent case in 2008, the

[6] Case No. ER-2008-0318, Report and Order p. 65.

Commission approved the FAC and noted that the "Commission's previous focus solely on coal purchase costs was misplaced."[7] The Commission, like witness Brosch, concluded that there was volatility in the off system sales and further that the volatility warranted an FAC. The Commission specifically stated that annual rate cases are not a solution for regulatory lag as it relates to the cost of fuel and purchased power and the impact on the ability to earn the allowed return. The Commission noted that the reasonable opportunity to earn the allowed return is indeed the basis for determining if an FAC should be approved. In that regard I agree with the Commission as has every other non-restructured state for virtually every utility operating in a fully bundled jurisdiction. It should also be noted that even in restructured jurisdictions (such as Illinois, for example), utilities are assured recovery of the costs they incur to meet the provider or supplier of last resort obligation. The Commission went so far as to conclude that the statement quoted by witness Brosch related to rising costs not being the basis for an FAC was "simply wrong."[8] Thus, witness Brosch is simply wrong when he states that rising costs is not a rationale for approval of an FAC and that regulatory lag is a reasonable incentive for the utility to manage its fuel costs at the expense of an inability to earn the allowed return.

Q. Is the stability of coal prices the only factor to consider in determining fuel and purchase power price volatility in the IM market as suggested by witness Brosch?

A. No. Witness Brosch implicitly assumes that the average delivered cost of a kWh is solely a function of the price of coal delivered to the plant. Such an assumption is incorrect. The average BTU content of coal differs by source and even from the same source with

---

[7] Op. Cit. p. 63.
[8] Op. Cit. p. 67.

the typical contract permitting about a two percent variance in the BTU content of the coal shipped. Even a two percent difference in BTU content will impact the amount of coal burned to generate a kWh. For each coal fired generation unit the heat rate curve determines the amount of coal required to produce a kWh at various plant load levels. The heat rate curve is typically U-shaped meaning that as output increases initially, the BTUs required to generate a kWh declines. At some point equal to less than the full load rated capacity of the plant the heat rate curve reaches a minimum BTU input per unit of output. Beyond that point, the required BTUs to generate a kWh increase. Thus the same ton of coal may produce a different cost of power depending on the level of output from the generator. Since the level of output is calculated to minimize the total system costs, unit availability across the SPP system will determine how the KCP&L units operate and the nodal delivered price of power. The dynamics of the power system establish nodal prices in a day-ahead market and a real time market. The above factors and many more create volatility in the cost of power for KCP&L native load and for the credits that result from the sale of off-system power. It is also the source of the inability to forecast power costs with reasonable accuracy in the Rate Effective Period because there are too many elements to make a reliable forecast. The actual fuel and purchased power costs that KCP&L incurs will be impacted by weather, load levels, time of day, wind, solar insolation[9], scheduled maintenance, forced outages, the price of natural gas delivered at the natural gas plants across SPP, the delivered price of coal, the nuclear refueling cycle, the availability of water, unit deratings, transmission congestion, ramp rates and many more factors across the integrated system. In addition to all these factors there is an interrelationship between factors such that low water for hydroelectric

[9] The amount of solar radiation reaching a given area.

generation would mean more thermal generation. Less wind will mean more night time generation and potentially more spinning reserve. Since a nuclear plant has a refueling cycle of between 18 and 24 months, the cost in any twelve month period will be impacted by whether refueling is required in the period as this will also impact the level of other thermal generation with costs typically higher than the nuclear costs. As a result, there is virtually no chance that fuel and purchased power costs in an actual period will equal the estimate used to set the base rate amount. Costs may be higher or lower based on numerous factors that cannot be controlled by KCP&L and even the other members of SPP. In each case where the Commission has approved an FAC, the Commission has correctly found that the cost of fuel is market based and that utilities do not make the market.

Q. Does management have control over the variability of all the factors that impact the cost of fuel and purchased power as implied by witness Brosch in his discussion of hedging and forward contracts?

A. No. Management operates the system and controls as many elements of price as possible and witness Brosch seems to agree that these activities are both prudent and worthwhile. Beyond these few examples witness Brosch seems to believe that there are no other factors that create volatility in the cost of fuel and purchased power. Witness Brosch is simply wrong about the control KCP&L management has over the numerous factors that impact FAC costs and the volatility they cause. While the Company has operating control over the plants they own, there is no control over many of the factors that directly impact own load costs and off system sales margins because they do not control most of the other variables that impact ultimate costs. For example, there is no control by

KCP&L when nodal prices might be negative because of too much wind or when all of the hours of a day may have natural gas as the marginal fuel even though hourly prices vary significantly based on the heat rate of the marginal gas fired unit that may vary based on the age and technology of the units that are not owned or operated by KCP&L.

Q. Please discuss the position of OPC witness Mantle as it relates to the FAC.

A. Witness Mantle opposes the implementation of an FAC related to the settlement agreement provisions. Failing that argument the witness opposes the FAC on grounds that the utility has not met the criteria for an FAC. Finally, in the event that the Commission approves an FAC witness Mantle proposes that the utility recover only 50 percent of the increases and refund only 50 percent of any decreases. This latter type of proposal is not new from the OPC and has been specifically rejected by the Commission previously in approving the Ameren FAC.

Q. Does OPC witness Mantle discuss the incentives related to regulatory lag as it relates to the historic test year and no FAC?

A. Yes. Witness Mantle includes a discussion of the regulatory lag provision in her discussion of the regulatory history predating the statutory change that authorized the FAC.

Q. Is this discussion useful in the context of evaluating the current proposal?

A. It is certainly useful to understand why the public interest is not served in the absence of an FAC. It is also of interest relative to the bias inherent in the OPC proposals. Witness Mantle says that if costs were higher in the Rate Year the “utility” would bear the costs. In fact it is not the utility that bore those higher costs but the equity holders who bore the costs for services provided to customers at their expense for costs beyond the reasonable control of the utility and in violation of the constitutionally mandated principle of providing the utility a reasonable opportunity to earn a reasonable return. Nor does witness Mantle point out that if the costs in the Rate Year were lower than the test year costs, the shareholders earned returns greater than authorized at the expense of customers who paid too much without any effort on the part of the utility because it could not control the costs in any event. Witness Mantle also correctly recognizes that the only option available to the utility was to file more frequent rate cases at added cost to customers when costs exceeded the base FAC costs in rates. As a practical matter, the level of unrecovered costs could be exacerbated by general inflation in that period that would substantially exceed the potential available pool of productivity and efficiency gains virtually assuring under earnings unless weather or load growth resulted in substantial growth in volumetric sales so that non-fuel related revenues rose rapidly enough to mitigate these risks. It was in this period that utility credit ratings deteriorated significantly raising the long-run costs for financing the capital intensive electric industry. Witness Mantle did not include these facts in her dive into the history and as a result fails to provide the complete picture of the absence of an FAC and useful background for the Commission's evaluation of the KCP&L proposal.

Q. Do you agree with witness Mantle's view that the FAC removes the historical incentive to accurately estimate fuel costs in a rate case?

A. No. This view is not correct for the simple reason that it implies first an ability to accurately estimate fuel costs in the IM environment and second the incentive that other parties have to underestimate the FAC related costs in the absence of an FAC. The first point relates to the fact that basing an estimate under a new paradigm (SPP-IM) for determining the cost for fuel and purchased power with almost no historical operating data and requiring a dispatch model that handles the entire SPP footprint with many more units, many more load nodes and many more operating constraints can be done accurately even for normal weather and current fuel costs or even forecast fuel costs (including all of the fuel purchasing strategies of investor owned utilities, non-regulated utilities and independent power producers) is a complex task at best and impossible at worst. The second point is obvious in that the under estimation of fuel and purchased power costs results in lower rate relief and lower rates for customers at the expense of shareholders. There is no reason to believe that accurate estimates of the FAC related costs are any more accurate in the absence of the FAC then they would be with an FAC when the estimate has less consequence for all parties. There is no advantage gained by any party promoting one estimate over another with a full tracking FAC since any estimate is trued up to actual Rate Year costs.

Q. Does the FAC provide little incentive for the utility to be efficient in purchasing and managing its fuel and purchased power costs?

A. No. This is an old argument that has been addressed by legal scholars and regulators. For example, the New York Public Service Commission initiated a generic investigation of the fuel adjustment clause in 1977 and simultaneously considered the Public Utility Regulatory Policies Act of 1978 (PURPA) requirements to consider standards related to automatic adjustment clauses. The PURPA requirement included a provision related to "incentives for efficient use of resources (including incentives for the economical purchase and use of fuel and electric energy."[10] As explained in detail in the attached

[10] OPINION NO. 80-24, CASE 27137 - Proceeding on Motion of the Commission to Investigate Fuel Adjustment Clauses of Electric Utilities, June 18, 1980, p. 5.

white paper the New York Commission concluded that the FAC is just a mathematical formula included in the rate schedules of the utilities.[11] The New York Commission also recognized that the FAC related costs cannot be projected accurately and are only susceptible to review after the expenses are actually incurred.[12] This is precisely the result required by the Missouri Commission regulations that require review and audit of these costs. With respect to incentives the New York Commission found that there were a number of incentives for the utility to minimize fuel costs as follows:

1. The lag period between the time the FAC related costs are incurred and when they are recovered in the clause;
2. Higher fuel cost inventory costs;
3. Failure of the FAC to compensate the utility for the higher working capital costs;
4. Sales declines associated with higher costs that impact base rate cost recovery; and
5. Commission audit and review of FAC costs and potential disallowance of costs found to be imprudent.[13]

Based on my experience these are all incentives that result from the KCP&L proposed FAC and directly refute the claim made by witness Mantle. There is also one more observation from that New York Commission order that is in stark contrast to the positions of the parties opposing the FAC in this case. The order notes that "no party seriously questioned that the presence of a fuel adjustment clause tends to diminish incentives for economy that would normally exist in the regulatory process."[14] The contrast demonstrates the willingness of parties to this case to presume bad faith on the

OPINION
[11] Op. Cit. p. 12.
[12] Op. Cit. p. 13.
[13] Op. Cit. p. 22.

part of utility management in contradiction to the presumption that utilities acted prudently absent a showing of imprudence. Since prudence is about facts, there is no basis for the parties or the Commission to prejudge the actual costs to be incurred as less than efficient. In particular, the impact of higher fuel cost pass through on sales volume has a much larger effect on earnings since these charges represent more than 75% of the operating expenses.

Q. You noted above that legal scholars have discussed this issue. Please explain.

A. In 1980 now Senator Elizabeth Warren wrote an article for the Notre Dame Law Review entitled “Regulated Industries' Automatic Cost of Service Adjustment Clauses: Do They Increase or Decrease Cost to the Consumer” in which she discuss the issues of incentives associated with fuel adjustment clauses. In that article Senator Warren addresses the issue of the incentives associated with regulatory lag. In that article she concludes that “protecting the financial integrity of the public utility is in the interests of both the utility customer and the utility investor.”[15] Senator Warren devotes a number of pages to the role of regulatory lag as an incentive mechanism. Among her conclusions are the following statements:

1. As an efficiency incentive, regulatory lag functions poorly because neither the rewards nor the punishments that flow from it bear a direct relationship to the company's efficiency.
2. Regulatory lag simply operates as a squeeze on the utility. The need for the squeeze, the degree of squeeze, and when the squeeze should be applied are not issues that commissions consider when they permit regulatory lag.

---

[14] Op. Cit. p. 22.

3. High inflation during a regulatory lag period may impair the efficient producer's financial integrity.
4. Regulatory lag is at best an "inadvertent," "crude," and "clumsy" tool to promote utility efficiency.[16]

Senator Warren concluded her discussion of the incentive role of regulatory lag as it relates to the FAC concept by saying "That regulatory lag continues to protect consumer interests and is the best available means of providing efficiency incentive is demonstrably a fallacy."[17] This analysis of the incentive concept is wholly consistent with views of utility Commissions around the country who have approved full tracking fuel clauses as a means of meeting the concept of a just and reasonable rate that allows the utility a reasonable opportunity to earn its allowed return. It is fair to conclude that witness Mantle's view of the incentives under an FAC are not supported by anything other than a distrust of both the utility and the regulator who oversees the operation, audit and prudence of the FAC as proposed by KCP&L.

Q. Does witness Mantle discuss issues related to the public interest and the impact on consumers as part of the rationale for approval of the FAC?

A. Yes. Witness Mantle discusses both these issues.

Q. Please comment on the role of these two issues as it relates to approval of an FAC.

A. With respect to the public interest concept both the enabling legislation and the Commission's rules define the parameters of the public interest standard. If the proposed FAC meets the legislative and regulatory standards for approval and the proposed rates

---

[15] Regulated Industries' Automatic Cost of Service Adjustment Clauses: Do They Increase or Decrease Cost to the Consumer", Elizabeth Warren, Notre Dame Law Review, Volume 55, Issue 3, Article 2, p. 338.
[16] Op. Cit. p. 348.
[17] Op. Cit. p. 351.

resulting from the approval are just and reasonable, the proposal satisfies the public interest standard. Based on the evidence before the Commission, the public interest standard has been satisfied. Without a full tracking fuel adjustment clause KCP&L will be deprived of a reasonable opportunity to achieve its Commission-authorized return because the combination of an historical test year and an unknowable level of net fuel costs will not possibly match the Rate Year actual costs to the detriment of either customers or equity shareholders. Since KCP&L is only entitled to recover prudently incurred costs and those costs cannot be known or determined in advance of the Rate Year, the FAC is the only reasonable approach to protect both customer and shareholder interests. That view is consistent with regulatory policy in every state where utilities are vertically integrated, and in every state where utility service is unbundled there is a provision to match the cost of power for the utility as the provider of last resort in the Rate Effective Period. It is obvious that the FAC is in the public interest given the near unanimous availability of a clause that matches precisely the costs and revenues to the benefit of customers and equity shareholders. Further, we know that the existence of an FAC is not a guarantee that the utility will achieve its Commission-authorized return because if it were every utility would be earning its allowed return and that is not the case even with many more adjustment clauses than the FAC.

As to the issue of customer impact, the regulatory compact requires that customers pay for the costs they impose on the utility and that they should not pay more than the actual costs. This policy is sound because absent paying the full cost of energy, customers will not be efficient in making their energy purchase decisions (a proposition that is inconsistent with PURPA requirement for efficient use of resources). It is also important to note that if customers pay too much for energy because of forecast error or unknowable and uncontrollable market conditions, customers' energy purchase decisions will also be inefficient. Customers interests are served along two important dimensions by the existence of a full tracking FAC as proposed by KCP&L. First, where rates match costs in the Rate Effective Period customers are provided the appropriate price signal necessary for them to make efficient energy purchase decisions. Efficient purchase decisions increase social welfare for all customers. Second, as noted by Senator Warren, the FAC protects the financial integrity of the utility (including satisfying the constitutional mandate expressed in Supreme Court decisions such as Hope and Missouri *ex rel.* Southwestern Bell Tel. Co. and providing credibility to the regulatory compact) for both the utility customer and the utility investor. Witness Mantle's view of protecting the customer in the absence of a full tracking FAC is simply shortsighted and wrong.

Q. Witness Mantle opines that fixed costs should not be included in the FAC. Please comment on this blanket exclusion.

A. With respect to the recovery of fixed costs, it is important to note that all fixed costs do not have the same characteristics. Some costs are fixed for the duration of a contract such as those in a long term power purchase agreement and those costs have been excluded from the KCP&L FAC proposal. Other fixed costs are subject to periodic adjustment as the result of using a formula rate to determine the costs. To the extent that any transmission owners in SPP have formula rates approved by the FERC, those costs are adjusted annually. The amount of the adjustment is unknown but the adjustment (up or down) will occur annually. This will impact both firm and non-firm charges under the SPP OATT. In addition, for those utilities that use a stated rate, those rates may change at any time based on a filing by the utility. Rates may become effective as soon as one day after the proposed effective date subject to refund. Allowing the utility to pass these costs through the FAC avoids the issue of allocating any potential refund since customers will have paid the rates they would be entitled to the refund in total. If customers did not pay the rates for the entire period the refund would need to be allocated between shareholders who absorbed the costs initially and customers who later begin paying the costs. Further, even since witness Mantle filed her testimony the FERC has proposed to allow interstate pipelines to file for and receive approval of an infrastructure adjustment clause to recover pipeline safety and integrity costs through a RAM. As such, fixed charges for gas transportation have become more variable. In either case, the pass-through of these changes of FERC approved charges would be consistent with recovery of prudently incurred costs that are unknown and uncontrollable changes for KCP&L.

Q. Are witness Mantle's arguments related to off-system sales and the impact on fuel costs a valid reason for not approving the proposed FAC?

A. No. Witness Mantle seems to not understand that the determination of the native load costs (those costs to be recovered under the FAC) has changed dramatically with the advent of the SPP IM. It is understandable that witness Mantle may not have experience with the SPP IM market since this is new. These types of markets have been used in other areas of the country for some time and include PJM, NYISO, MISO, ISO-NE and CAISO. Since this market structure fundamentally changes the day-to-day dispatch of generating units and the native load cost of power, the FAC must reflect the new system that basically includes the purchase and sale of every kWh of native load and generation. KCP&L records the costs associated with both native load and off-system sales separately. Ultimately native load costs are determined by the power produced and purchased from IM to serve native load net of the margins resulting from serving off-system loads. Failure to recognize the impact of the SPP IM on the costs of fuel and purchased power cannot reflect the enhanced efficiency of the market place in determining energy costs for KCP&L customers. Witness Mantle's table of cost volatility is a telling example of the lack of understanding of the changed paradigm for power supply costs. In that table volatility is measured from a time period that does not include even the start of the SPP IM. This new model represents a fundamental departure from dispatching KCP&L units to serve its native load plus off system sales that may or may not have been all of the possible sales that could have been made and may or may not have resulted in the lowest cost dispatch of the KCP&L generation fleet. Instead, KCP&L units and all of the other units in SPP are dispatched to minimize the cost of all loads in SPP and to compensate plant owners for the full avoided costs of the power they supply to loads on the system. Witness Mantle's conclusions about the role of purchased power and off system sales demonstrate a fundamental misunderstanding of the how native load costs are completely intertwined with the sale and purchase of off system power that occurs in every hour of the year. The FAC costs in essence are composed of a net cost of purchased power for native load and net cost of generation for native load plus the net effect of off system sales. This value, however, cannot be calculated in these components because all production is sold to the grid and all power is purchased from the grid as simultaneous transactions. Further, these transactions occur at various nodal points on the system that have different prices every hour in both the day ahead and real time markets with the actual final costs of purchases and sales not known until settlement. The actual fuel and purchased power costs for KCP&L are also known from each plant that operates during the month so that the net native load costs may be calculated and allocated to jurisdictions based on the allocation factor in the FAC. Witness Mantle's views are predicated on a market concept that is no longer used and should be rejected.

Q. Witness Mantle suggests that risk decreases with the implementation of an FAC. How does that change impact the cost of capital?

A. Since all of the comparable companies used in determining the cost of equity have FAC mechanisms or the equivalent in restructured markets for the utilities' provider of last resort obligation, the estimated cost of capital based on these utilities reflects the existence of a full tracking fuel adjustment clause. From a risk perspective if the FAC is not granted the risk for KCP&L will be higher than that of comparable companies and a higher market cost of equity would be required to recognize this risk. Thus witness Mantle's concern for lower risk is unwarranted unless she believes that the Commission would only grant the same return without an FAC as it would grant with an FAC. Such a belief is inconsistent with prior Commission decisions where equity returns were adjusted upward in the absence of an approved FAC[18].

Q. Is witness Mantle's view of the customer impact of an FAC telling as it relates to her view of fuel costs in base rates?

A. Yes. Witness Mantle essentially assumes that the fuel costs in base rates will be lower than the costs actually incurred in the Rate Year. She states in her testimony that the KCP&L FAC will likely "increase the dollars going to KCP&L." This is an admission

[18] Report and Order, May 22, 2007, Union Electric Company d/b/a Ameren Missouri, Case No. ER-2007-0002, page 43.

that she does not believe the forecast of base rate costs actually represents the costs that will be incurred in the Rate Year and as a result that the absence of an FAC will deprive the utility of a reasonable opportunity to earn its allowed return. Witness Mantle completely ignores the fact that under the new SPP IM, that costs may be lower as a result of the higher value placed on the KCP&L generation fleet in the market because it is a low cost, efficient provider. The view that costs will only increase is equivalent to saying that the Commission has no obligation that just and reasonable rates provide a reasonable opportunity to earn the allowed return as required by the regulatory compact.

Q. Witness Mantle provides a fall back provision that if the Commission approves an FAC the FAC should recover or refund only 50 percent of change in costs. Please comment on this proposal.

A. The Commission has already rejected this proposal from OPC in a prior proceeding[19] and nothing has changed in this testimony to support this type of proposal. Importantly, such a proposal makes the estimation of fuel and purchased power costs in base rates more important and prompts parties to adjust the base to protect their interest far more than any potential for biased estimates that witness Mantle claims as a rationale for rejecting the FAC. Simply, the use of any disallowance of costs or refunds under the FAC is contrary to the stated constitutional and regulatory compact provisions that utilities should be afforded a reasonable opportunity to earn the allowed return. To be afforded that opportunity the uncontrollable delivered cost of power and inability to accurately forecast the expense of that power (the largest single cost item in O&M costs) should be matched dollar for dollar in the Rate Year to meet the standard of just and reasonable rates. Since

[19] The Commission finds that the 50 percent pass through proposed by Public Counsel is inappropriate because it would largely negate the effect of the fuel adjustment clause. Report and Order, Case No. ER-2008-0318, p. 72.

the actual amount of the FAC expenses cannot be known in advance, the matching principle and the assessment of prudence can only occur in a post decision review after the costs are actually known. A discount of any amount is simply a way to penalize or reward the Company for results that are more dependent on a forecast that all parties knew would be wrong than any logical implementation of the requirement for matching costs and revenues in the Rate Year. This type of proposal, albeit at a 5 percent band, has been accepted in Missouri as an incentive without any critical review of the logic that dictates such a mechanism has no incentive properties whatsoever. Since the actual costs to be recovered are not known at the time base rates are set there may be an unintended windfall for customers or shareholders that is inconsistent with the full recovery of prudently incurred costs. Prudence can only be discerned after the fact when these costs are known and auditable. The prudence incentive is strong rather than weak as stated by witness Mantle. Any record of imprudence among other penalties calls into question the use of the FAC. Further, if the costs are prudent, and there is no reason a priori to expect otherwise in light of the Commission's requirements related to review, then the concepts of matching and providing a reasonable opportunity to earn the allowed return are only satisfied by a full tracking fuel adjustment clause. Any dead band adjustment for an FAC should be rejected in favor of the KCP&L proposal. The full tracking fuel clause permits bilateral fairness between customers and shareholders, gives credibility to the regulatory compact and meets the statutory standards for just and reasonable rates.

Q. Witness Mantle, like witness Brosch, also states that there is no incentive under the FAC for KCP&L to manage its fuel and purchased power costs efficiently. Is that correct?

A. No. I have discussed this issue above in detail and that discussion demonstrates that this view is not sound based on all of the points I have noted. I would just add one point based on witness Mantle's own testimony. Just prior to the discussion of the absence of incentives, witness Mantle notes that "the customer's only way to manage their risk is to use less electricity." This customer response by itself provides an incentive for KCP&L to manage its fuel and purchased power costs efficiently since using less electricity with volumetric recovery of fixed costs means that every cent of that reduced consumption represents a lower earned return for KCP&L. That is a large incentive to be efficient in managing FAC costs that witness Mantle implicitly acknowledges but fails to recognize as an incentive and likely the largest incentive for KCP&L to be efficient. It makes no sense that that a utility would act inefficiently relative to recovery of an expense when the customer response to that inefficiency reduces its return.

Q. Does the Staff of the Commission oppose the implementation of the FAC?

A. As with other witnesses, the Staff opposes the FAC on the same two grounds as witness Brosch and witness Mantle. The first relates to the prior settlement and the second relates to demonstrating the need for a clause. The Staff also proposes an alternative FAC if the Commission finds an FAC appropriate. I have discussed in detail the reasons that an FAC is required and satisfies the Commission standards for approval. I will not repeat those arguments here since Staff provides no new views relative to the control of costs or the volatility of costs that I have discussed in detail above. I would merely note that the Staff review makes the same mistake of the other parties' relative the volatility of prices of KCP&L's own fuel but ignores the SPP IM market impacts all together. The SPP IM discussions above become a critical component for rejecting the Staff's incorrect views on management control and cost volatility.

Q. Does the Staff recommend a different FAC if the Commission finds that just and reasonable require and FAC?

A. Yes. The Staff recommend changes to the proposed FAC in four regards as follows:

1. A reflection of only 95 percent adjustment of changes in costs up or down as compared to the base rate fuel cost determination;
2. Exclusion of Southwest Power Pool ("SPP") Schedules 11 and 12 costs and revenues;
3. Exclusion of SPP Schedule 1-A administrative charges; and
4. KCPL should provide additional monthly filings that will aid the Staff in performing FAC tariff, prudence and true-up reviews.

I will discuss only the first three of these changes since the data needed to review the FAC should be developed consistently for all FACs and not based on a piecemeal Company by Company approach.

Q. Is 95 percent recovery of prudently incurred costs appropriate?

A. No. There is no logical rationale to support this disallowance of costs or provision of an earnings windfall as I have discussed in detail above. I recognize that this recommendation is consistent with the other utilities in the state and represents an easy way for the Staff to propose a modification to the FAC. I would note two points in that regard. The Commission is not bound by a prior decision in this case. Certainly the evidence is different in this case based solely on the new market paradigm created by the SPP IM. Second, the evidence provided in this case points to numerous issues that show that denial of cost recovery is neither an incentive nor a just and reasonable outcome in connection with establishing an FAC. The Staff's proposal to reflect in the FAC only

95% of cost increases or decreases in comparison to the base rate allowance should be rejected for all the reasons discussed above.

Q. Is it reasonable to exclude Southwest Power Pool ("SPP") Schedules 11 and 12 costs and revenues from the FAC?

A. No. These exclusions are arbitrary and are inconsistent with the way costs are incurred. In the case of both schedules the actual costs cannot be determined in advance since both the billing determinants and the revenue requirements vary over time. A careful review of the revenue requirement as it relates to Schedule 11 allows any owner to file for a change to a stated rate and with regulatory approval those costs will pass through the revenue requirement. In addition any utility with an approved formula rate may also pass through those costs on approval of the formula filing. All of those costs become part of a revenue requirement that is not fixed in total for more than twelve months. The operation of the formula rate is such that unless the fuel and purchased power costs are trued up just prior to the effective date of a new formula the costs approved in base rates will not be correct and even then the actual costs for any customer will vary from month to month and only in total would revenues match cost for zones. This is a perfect example of why an FAC is the reasonable method for responding to a matching of costs and revenues in the Rate Year. Further, depending on the Rate Year, even setting the costs at the day before new rates take effect would not match costs unless that date coincided with the effective date of a new formula rate filling for each transmission owner. It would also not match the rates of any stated rate that changed within the Rate Year. Finally, the revenue requirement under Schedule 11 is allocated based on the monthly peak load each month and thus varies from month to month but in total recovers the annual transmission revenue requirement. This charge can only be determined after the fact and thus cannot be estimated with any reasonable accuracy. Schedule 12 is a similar factor with two exceptions. First, the revenue requirement is billed on an estimate of the FERC assessment and subsequently trued up when the actual assessment is known. The actual charge is not known until the megawatt-hours of energy transmitted in interstate commerce for a year is known and the FERC approved assessment is applied. This means that the actual cost of this charge for the Rate Year is unknown until after the conclusion of the Rate Year. This is just another example of the need for a full tracking FAC. The fundamental point being that if every item that is unknown or unknowable but nevertheless a cost is excluded from recovery and true up there can be no possibility of matching costs and revenues in the Rate Year.

Q. Is it reasonable to exclude the recovery of charges under SPP Schedule 1-A administrative charges from the FAC?

A. No. As with the other schedules discussed above this provision to exclude these costs is unreasonable and defies the logic underlying the SPP IM. These costs are associated with among other things managing, planning and operating the combined systems for the benefit of the members and their customers. That is the IM is the basis for determining the power supply costs for KCP&L customers and would not occur without the costs of operating SPP. These costs are not known in advance since both the allocated share of these costs and the actual total costs change through use and a true up to the actual cost incurred under and FERC approved Tariff. It is not reasonable to disallow the pass through of costs that KCP&L cannot avoid and are judged to be prudent by the FERC. Thus these costs should be part of an approved FAC.

IV. Trackers

Q. Have you reviewed the testimony relative to the use of trackers?

A. Yes.

Q. Do you have any general comments related to the use of trackers as a regulatory policy tool?

A. Yes. As a general policy regulatory commissions have begun to use both RAMs and trackers as discussed above in the Missouri regulatory model for more than just the traditional fuel and purchase power expenses. The issues of trackers are discussed in more detail in "Modernizing Utility Ratemaking Practices in a Changing Industry" that is attached as Sch. HEO-2 to this testimony. As a vehicle to address regulatory lag trackers as proposed by KCP&L are less useful than the RAM type mechanisms employed elsewhere. Since these trackers are fundamentally different than a RAM as I explained above, the analysis of the tracker must be reviewed by a different standard than the RAM. In no way do trackers match costs in the Rate Effective Period, nor do they even mean that the pernicious impact of regulatory lag will be any more than partially offset by such a tracker. Trackers for specific costs will, however, improve the utility's ability to earn the allowed return while also protecting customers from being exposed to excessive utility returns.

Q. Have you reviewed the testimony of MECG witness Brosch related to the proposed trackers?

A. Yes.

Q. What does witness Brosch conclude relative to the proposed trackers?

A. Witness Brosch concludes that KCP&L does not need and should not be granted the proposed trackers. Witness Brosch bases the recommendation on his application of applied regulatory criteria and his view that the Company has not justified its proposal for "extraordinary" treatment of these expenses.

Q. Does witness Brosch propose criteria for the use of trackers?

A. Yes. Witness Brosch has confused the use of AAO and trackers in his review of trackers by citing to the Commission's Report and Order which relates to a request for an AAO[20]. In his discussion he assumes that both an AAO and a tracker are the same and thus impute the standard for AAO approval to the requested trackers. The AAO standard of extraordinary costs is not the same standard for approval of a tracker which is a different mechanism altogether as discussed above. To this incorrect view of trackers witness Brosch also adds a set of additional criteria. The five additional criteria are as follows:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels.
3. Volatile in amount, causing significant swings upward and downward in income and cash flows if not tracked.
4. Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews.

[20] Brosch Direct Testimony at p. 10 footnote 9.

5. Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.[21]

Certain of these standards are not consistent with the purpose of a tracker and are not based on a sound process for logical review as discussed below. Other portions of the standard are axiomatic to the concept such as being beyond the control of management.

Q. Why is the first standard "Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases" not a reasonable standard?

A. Trackers are not designed to be guarantees of a return on equity. Rather, they are designed to make it possible for the revenue requirements approved by the Commission to meet the standard discussed by witness Brosch when he states "The fundamental concept behind traditional utility regulation is that, in the absence of competitive markets to determine pricing for an essential public service, just and reasonable utility rates should be determined based primarily upon *careful measurement of the utility's prudently incurred costs* to provide such monopoly services." (Emphasis added.) Indeed, this is the same point made by the Commission in the recent Ameren decision where it states "Rate making is designed to be forward looking. The goal is to choose a representative test year to estimate what costs will be when rates are in effect…"[22] The use of a tracker recognizes that some costs cannot be carefully measured using historic test year values. Thus, costs that vary from year to year based on the requirements of a prudently managed program may not be "normalized" in order to provide for that careful measure of prudent costs. Since the costs are variable, unpredictable and opportunistic, neither utility nor the

[21] Op. Cit. p. 18
[22] Report and Order, File No. ER-2014-0258, April 29, 2015 (Ameren Decision), p. 29.

customers may be treated equitably by a normalized cost level because it cannot be measured and estimated with any reasonable level of precision. Using a tracker assures that only the actual, prudently incurred costs are recovered and then only if a subsequent review justifies the tracker recovery. The tracker provides for both a balanced assessment and assurance of prudence. The idea that trackers only work for a material impact on revenue requirements suffers from the same logical flaw as it relates to the FAC. The purpose of the tracker is to provide a reasonable opportunity to earn the return on equity. Strict adherence to an earnings standard for each tracker would be inappropriate as well since by disallowing each proposal individually may not be significant but in total all trackers may have a significant impact on equity return.

Q. Is the requirement that costs be volatile a sound basis for assessing a tracker?

A. No. For example, the costs need not be volatile if circumstances make it impossible to arrive at a "representative estimate"[23] for use in determining the test year. The tracker mechanism in that case becomes the most reasonable ratemaking tool for setting just and reasonable rates for the test year. Effectively, the rate is determined by a separate formula for specific costs that guarantees matching without guaranteeing recovery. Failure to match prudently incurred costs is simply a way to assure that the utility has no reasonable chance to earn its allowed return.

Q. Is the requirement that the tracker be "Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews" reasonable?

A. This standard is only partially applicable. Sound criteria for a tracker includes that the formula be well defined, although in some cases that may not be a simple formula, and readily auditable in any event. However, the idea that it be treated through an expedited regulatory review is not consistent with my understanding of the Commission's requirement that the tracker be considered in a rate case where all of the relevant information may be considered. The expedited review implies that the tracker deserves some unique treatment that has not been proposed. In that context this provision would add confusion to the assessment of a tracker mechanism.

Q. How does the recommended standard of a balanced review play a role in the determination of the need for a tracker?

A. It does not play any role in determining whether a tracker should be approved as part of a rate case. The purpose of a tracker is to provide an opportunity for balance that would not exist in the absence of the tracker. Where the actual Rate Year level of prudent costs cannot be forecast with sufficient accuracy by an historic test year, the mandate to allow a reasonable opportunity to earn an allowed return and the obligation to assure that rates are just and reasonable can be met only by two regulatory tools - either permit a tracker or allow an estimated value for the costs without regard to actual test year data. The estimated value to be used would be consistent with a forecast test year or the addition of an inflation adjustment to the historic test year as used by other commissions. The tracker mechanism is the better option because there is no potential for a mismatch, no potential for imprudent costs to be recovered and opportunity for a full review and determination as to the amount of costs, prudently incurred, to be recovered in a subsequent rate case review.

---

[23] Op. Cit. p. 29.

Q. Is it necessary to have a set of standards that must be met in order for a tracker to be a just and reasonable ratemaking tool for the Commission?

A. Based on the Commissions view of using trackers sparingly and based on circumstances that exist in the determination of test year costs and revenues as defined by the Commission, it would seem that a set of standards could not reasonably be developed. Every application for a tracker could not be neatly packaged into a set of standards for every circumstance where the historic test year could not produce a reasonable estimate of costs in a Rate Year. The Commission has correctly noted "sometimes the utility incurs an expense that the Commission believes should be deferred for consideration for recovery in a future rate case" and "there may be other public or regulatory policy reasons why a utility should be allowed to defer a cost for consideration for recovery in a future rate case."[24] The important point is that the Commission has discretion to recognize shortcomings in the test year estimates of Rate Year costs and provide tracker mechanisms that meet its statutory obligations. It is important to note that the Commission makes it clear that the tracker is not a certainty of recovery but is an option to provide for consideration of actual costs as the basis for recovery in a future rate case.

Q. Please identify the three proposed tracker mechanisms.

A. KCP&L proposes the following operating expenses be tracked during the Rate effective Period:

Property Tax Expenses,

Critical Infrastructure Protection / Cybersecurity Expenses, and

Vegetation Management Expenses.

[24] Op. Cit. p. 31.

Q. Please discuss witness Brosch's view of tracker mechanisms in general.

A. Witness Brosch's general view of trackers may be summarized as general opposition to the use of trackers, an assumption that trackers only reflect costs that are rising, are unnecessary because KCP&L is earning an adequate return, that cost recovery is assured under a tracker and that trackers violate the matching principle. In addition it appears that Witness Brosch has conflated the concepts of a tracker and an AAO rather than maintaining the clear distinction as discussed in my testimony above.

Q. Please comment on these general views.

A. Witness Brosch's opposition to trackers is misplaced. There is a significant role for tracker mechanisms in regulation as demonstrated by the number and type of such mechanisms discussed in the Sch. HEO-2 report attached hereto. While trackers are used under a variety of regulatory test years for ratemaking purposes, just and reasonable rates based on a historic actual test period in particular have a role for the use of trackers. As I have discussed above, historic test years do not produce reasonable estimates of rate year costs when costs are rising, uncertain or subject to change based on political decisions, new regulations, uncertain rule makings from regulatory agencies and so forth. The concept that the test year matches expected costs is central to the opportunity to earn the allowed return. Importantly it is also essential to the matching principle discussed by witness Brosch. Finally, in order for the regulatory compact to have credibility among stakeholders, trackers provide a measure of bilateral certainty related to the tracked costs. The bilateral certainty arises because trackers are not a one way mechanism. Rather, trackers match actual costs with the allowed costs so that both increases and decreases in costs are recorded. Contrary to Mr. Brosch's apparent view, a tracker may also result in refunds to customers if base costs are over estimated in setting the Rate Year revenue requirements. Where costs are estimated fairly, one would assume that the probability of over-estimation is the same as under-estimation. Given witness Brosch's concern, I would suspect that he believes that test year costs are likely to be biased downward resulting in consistent understatement of those cost for the Rate Year. The existence of that bias is a sufficient reason to allow trackers if the Supreme Court mandate in the Hope case noted above is to have any meaning. Further, witness Brosch's view on the matching principle seems to be matching the estimate of costs and revenues in the test year and not a matching of actual costs incurred to actual revenues realized in the Rate Year. This view is both unreasonable and unfair, especially when it comes to costs over which management has little or no control such as the ultimate level of property taxes. Further, there is no reason for allowing the utility to profit when actual costs during the rate year come in lower than estimated in the test year when that estimated cost level was admittedly uncertain at the time the revenue requirement was set. The tracker mechanism assures the matching during the Rate Year but does not guarantee the recovery of those dollars. For example, there is no certainty that all of the dollars recorded in a tracker account will be approved for recovery in a subsequent rate case review.

Q. Witness Brosch suggests that traditional ratemaking under the regulatory compact is harmed by trackers. Is that view reasonable?

A. No. First I should note that witness Brosch incorrectly states that the utility selects the test year. The utility does not select the test year since any rational utility would always select a test year most reflective of the costs during the Rate Year. That year under current circumstances would be to use a forecast test year that matches the Rate Year as many utilities do in other jurisdictions, including the FERC. In some jurisdictions the test year is prescribed by legislation and neither the utility nor the regulator has any control over the test year. The implication that the utility has an ability to present its "desired" revenue requirement is simply wrong. Rather, the utility has the right to present a test year revenue requirement consistent with the requirements of the operating jurisdiction even when it knows that those revenue requirements will be inadequate to match the expected costs in the Rate Year. This is part of the reason that many commissions recognize the need for various RAMs and trackers to produce just and reasonable rates for utilities while still operating within the legislatively defined framework. It is also why Commissions allow a variety of adjustments to the test year for ratemaking purposes.

Q. Please discuss witness Brosch's views on regulatory lag as an incentive?

A. As I have discussed above the concept regulatory lag providing incentives is not sound for the reasons discussed. The concept of regulatory incentives for efficiency has resulted in major changes in regulatory models around the world where other regulators have adopted alternative regulation using performance based regulation (PBR) that actually provides incentives to improve performance through a formula specifically tied to productivity. I should also note that under PBR both RAMs and trackers are used to assure that costs beyond the control of the utility are matched dollar for dollar. Regulatory lag is a crude and unreasonable tool for promoting efficiency simply because it penalizes a more efficient utility more than an inefficient utility.

Q. Witness Brosch discusses a litany of characteristics related to revenue requirements determination. Is there a reasonable summary of all of those provisions?

A. Yes. Just and reasonable rates only result from a process that matches costs and revenue during the Rate Year. The test year (historic or otherwise) is a forecast of those costs and must be balanced to produce a credible decision. Trackers are a part of making that test year credible.

Q. Witness Brosch discusses the concept of prudence review? Please comment on that discussion.

A. There is no question that prudence is fundamental to allowing costs in rates. If expenses are imprudent they are removed before setting rates. The fundamental problem with witness Brosch's view occurs when prudent costs are excluded from the revenue requirement. If costs are not imprudent but are not recovered due to the use of biased estimation factors such as a three year average to estimate costs that are increasing every year but are not imprudent there is no incentive provided by regulatory lag, just a penalty. The same is true when costs such as property taxes are estimated based on actual cost from a prior period knowing full well that these costs increase from year to year because of added plant, increased tax rates and revised assessments, for example. Essentially the utility has no control over any part of this other than to make efficient additions to plant, but even that means higher taxes.

Q. Does a tracker eliminate the regulatory lag incentive?

A. No. Since there is no guarantee of cost recovery under a tracker, the incentive is not eliminated entirely. More importantly, the review of these costs in a future rate case still covers the prudence standard prior to inclusion in future rates. Thus, the tracker permits only the Rate Year matching of costs and revenues for prudent costs incurred beyond the reasonable control of management.

Q. Does witness Brosch use the wrong measure to assess the need for a particular tracker?

A. Yes. As with the FAC, witness Brosch continues to base his determination of impact on total revenue requirements or total operating expense. Since the Supreme Court requires that a utility be afforded a reasonable opportunity to earn the allowed return, the logical and correct comparison is to the dollars allowed for the return on equity. Thus a small change in a large cost or a large change in a small cost may have equivalent impacts of the opportunity to earn the allowed return. This is the critical comparison to assess the rationale for recovery. Further, it is not an assessment that should be based on each individual item proposed for tracking but rather for the aggregate of the elements. In this case it would be reasonable to consider all three trackers as a package that is designed in total to provide KCP&L an opportunity to earn the allowed return. Further, as the Commission noted with respect to the FAC in the Ameren decision discussed above, it is not merely volatility but consistency of cost of service increases (or decreases) that impact the opportunity to earn the allowed return.

Q. To your knowledge has witness Brosch made any proposal to implement his view that taxes are predictable and can be reflected in a test year?

A. No. If taxes are indeed predictable witness Brosch view of the revenue requirement in the Rate Year could be determined by increasing the property tax dollars from the 2014 test year by the expected increase for 2015 and 2016 to arrive at a test year value that is a reasonable prediction of those costs in the Rate Year. I do not believe that witness

Brosch has made such a proposal thus the proposed use of a tracker is a second best alternative for providing KCP&L a reasonable opportunity to earn the allowed return.

Q. With respect to other trackers are the arguments on individual trackers based on the same general principles?

A. Yes. The general arguments are the same with specific references to the data associated with each individual tracker proposal. As I have noted above, the tracker proposals should be thought of in terms of an overall just and reasonable rate level. Witness Brosch never even considers the totality of the potential impact on the ability of KCP&L to earn its allowed return. Further, since the tracker mechanisms are not a guarantee of recovery there is no reason to assume that the aggregate impact equals the deferred amounts in each tracker. Each tracker will be reviewed individually for prudence and recovery in the next general rate case and if approved amortized over the same period used to accumulate the costs.

Q. What is your recommendation related to the proposed trackers?

A. I believe that the proposed trackers should be approved because the trackers individually and collectively are critical elements of establishing just and reasonable rates for customers and shareholders.

V. Summary and Conclusions

Q. Please summarize your testimony as it relates to adjustment mechanisms.

A. It is critical to understand the fundamental regulatory and operating procedures for each of the rate adjustment mechanisms used in Missouri. Each of those regulatory mechanisms - RAMs, trackers and AAOs – is distinct and has different rationales for their use. I have carefully explained those differences so that the KCP&L proposals for an FAC (a RAM) and three trackers may be properly evaluated in the context of the correct mechanism. Each of these mechanisms proposed by KCP&L represents a necessary tool for use as part of a general rate case to allow a utility a reasonable opportunity to achieve its Commission-authorized return. These tools are important when coupled with any type of test year but even more important with a historic test year that does not allow for adjustments to match costs and revenues during the Rate Year, but assumes that historic data is a reasonable forecast of future costs. It is axiomatic that forecasts are wrong. To the extent that elements cannot be reasonably forecast based on current data, these regulatory tools are required to meet the constitutional obligation to provide a reasonable opportunity to earn its Commission-authorized return including recovery of actual expenses in the Rate Year.

Q. Please summarize your testimony related to the proposed FAC.

A. The FAC should be approved as filed. The change that occurred in 2014 to implement the SPP IM has fundamentally changed the net costs for fuel and purchased power as well as transmission costs. To accurately model these changes it would be necessary to model SPP not just KCP&L. Even if one could develop a reasonable estimate of net FAC-related costs the model would need to assume normal weather, normal insolation, normal wind, normal rainfall in all of the areas feeding hydroelectric facilities and so forth. It is unreasonable to expect that any estimate of base fuel cost recovery will match the actual cost in the Rate Year and beyond except by accident since costs vary with prices of fuel, delivery costs of fuel, the marginal plants in the SPP footprint by all 8760 hours in the year as well as many other variables. A full tracking FAC has been and will continue to be an appropriate tool for matching costs and revenues in the Rate Year.

Since there are bilateral benefits to customers and shareholders, a full tracking FAC is the only just and reasonable mechanism to satisfy the requirements of the regulatory compact and the various court mandates related to cost recovery and a reasonable opportunity to earn an allowed return. The FAC requirements and audit considerations assure that only prudently incurred costs are include in the FAC. Further, the audit will verify that no costs are double counted and that no incorrect costs are included in the FAC. The result is that customer interests are assured that the matching of cost and revenues has occurred. The approval of the KCP&L FAC is required if resulting rates are to be just and reasonable for both consumers and shareholders as I have discussed above.

Q. Please summarize your testimony related to the proposed tracker mechanisms.

A. Each of the proposed trackers is just and reasonable individually and as a collective proposal is necessary to provide KCP&L a reasonable opportunity to earn the allowed return. The tracker mechanism as used in Missouri has safeguards to assure that costs are both prudent and properly included in the tracker. As a result, these trackers should be approved as part of setting just and reasonable rates consistent with the regulatory compact.

Q: Does this conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light	)	
Company's Request for Authority to Implement	)	Case No. ER-2014-0370
A General Rate Increase for Electric Service	)	

AFFIDAVIT OF H. EDWIN OVERCAST

STATE OF GEORGIA)
) ss
COUNTY OF HENRY)

H. Edwin Overcast, being first duly sworn on his oath, states:

1. My name is H. Edwin Overcast and my business address is, POB 2946, McDonough, GA 30253. I have been retained to serve as an expert witness to provide testimony on behalf of Kansas City Power & Light Company.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of fifty-one (51) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

H. Edwin Overcast

H. Edwin Overcast

Subscribed and sworn before me this 5 day of May, 2015.

Notary Public

My commission expires: 12/11/2018

JASMINE C BROWNE
MY COMMISSION EXPIRES
NOTARY
PUBLIC
DECEMBER 11, 2018
HENRY COUNTY, GEORGIA

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director in the Management Consulting Division of Black and Veatch.

MODERNIZING UTILITY RATEMAKING PRACTICES IN A CHANGING INDUSTRY

BLACK & VEATCH PROJECT NO. 187810

PREPARED FOR

Kansas City Power & Light Company

7 MAY 2015

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF FIGURES

LIST OF SCHEDULES

LIST OF EXHIBITS

Introduction

Kansas City Power & Light Company (KCP&L) requested that Black & Veatch Corporation (Black & Veatch) prepare a report to assist it in evaluating utility ratemaking practices that could be adopted to address a continuing financial concern for KCP&L's management - the inability to earn its allowed rate of return on investment for its Missouri jurisdiction.

This report is structured to address the most significant issues related to modernizing electric utility ratemaking in response to the evolving business conditions utilities face. The utility industry is experiencing significant changes affecting virtually every part of the traditional utility business model. These changes are recognized by a broad spectrum of industry stakeholders, including a growing number of state utility regulators. In recent times, numerous trade journals and other industry publications have provided extensive comments expressing a wide range of viewpoints on this important subject.

In some states, utility regulators are also recognizing these fundamental changes to the utility industry, and have initiated comprehensive investigative proceedings to identify and analyze the changes occurring in the energy markets and to develop regulatory and ratemaking solutions that are supportive of the desired changes. For example, the New York Public Service Commission (NYPSC) has initiated a comprehensive docket[1] to investigate ways the energy industry and regulatory practices should be modified to address future industry changes. The NYPSC recently issued a major order in its proceeding that adopted a policy framework and implementation plan for the changes that will be made to its regulatory model and related policies.[2] In that order, the NYPSC found that, "Reforming the Commission's ratemaking practices will be critical to the success of the REV vision."

The current utility regulatory models and methods have been in use for well over a century. Over that period, fundamental changes to energy markets and the operating environment for utilities have occurred that the utility regulatory model has gradually adapted to in light of both regulatory policy and legislative changes. This section of the report provides a brief discussion of the changes in the utility industry that make it more difficult in the current environment to maintain the integrity of both the regulatory compact and the regulatory requirement for just and reasonable rates. The paper then discusses how the operating changes impact the various elements of the utility ratemaking process and provides some necessary policy considerations for addressing these changes. Details of the relevant issues and the regulatory/ratemaking solutions being implemented across the U.S. electric utility industry are discussed in the subsequent sections of the report. The last section of the report provides Black & Veatch's conclusions on the need for change in the utility regulatory area and specific recommendations on the ratemaking changes that KCP&L should consider to create a better alignment of interests among its customers and shareholders.

---

[1] NYPSC Case 14-M-0101, Proceeding on Motion of the Commission to Reforming the Energy Vision (the "REV Proceeding").
[2] Order Adopting Regulatory Policy Framework and Implementation Plan (Issued and Effective: February 26, 2015).

KEY BUSINESS CHALLENGES FACED BY THE UTILITY INDUSTRY

The electric utility industry faces numerous challenges as a result of both internal and external factors driving the utility business model and the ability of the utility industry to respond to the changes that it faces. Regulatory models and policies contribute significantly to the impact of these factors on utility economics. Importantly, it should be recognized that a one-size fits all approach to addressing utility issues cannot be applied because even the overriding issues do not have the same impact on each individual utility. In part, the differences are driven by the economics of the utility and of its service area. Utilities have different market models with some operating in markets with competitive energy providers. Some utilities operate in high cost regions. Some utilities are currently more exposed to change than others, but all utilities will eventually have to address the issues driving change. Five broad issues are discussed that are fundamental to the changes occurring to the utility business model:

1. Low customer growth;
2. Low or negative growth in energy consumption;
3. Requirements to replace or retrofit aging infrastructure;
4. New infrastructure demands associated with renewable resources and Distributed Energy Resources (DER); and
5. Disruptive cost changes for the infrastructure supporting technological innovation (e.g., grid modernization) and cyber security.

Within each of these issues are subsumed the factors most effecting the utility business and regulatory models under which utilities operate.

For much of the first 100+ years of utility regulation, customer growth and energy (kWh) growth was rapid as electric service expanded quickly by adding new customers and by adding load for existing customers. Customer and consumption growth provided utilities with opportunities for substantial economies of scale as unit costs declined overall with the addition of new facilities, growing rate base and earnings growth. Even with inflation, the economies of scale were large enough in some cases to offset those impacts and rates actually declined or remained flat as utilities had a reasonable ability to earn their allowed rates of return even with historically-based test years. Until the 1970s, utilities were strong financially with over 90% of utilities' bond ratings at A or above, and over 50% of the industry rated AA or higher.

From the 1970s to today, the utility industry has faced financial challenges of customer growth and growing investment in infrastructure in an ever-changing economic environment. Early in that time period, the robust growth required investment in new capacity for generation, transmission and distribution facilities. Over time, the growth moderated and the challenges required utilities to operate in a period of low growth with a need to address infrastructure issues including retrofit and replacement of the infrastructure developed prior to and during the earlier part of the past 40 years. During this period, both regulators and legislative bodies have recognized the constitutionally required need to provide for the financial health of utilities and have accomplished this financial health through changes in regulatory tools and policies. Even with changes designed to improve utility financial ratings, the number of A- or higher rated utilities had declined to just below 27% by 2011. The dual problems for utilities of customer growth and low or zero sales growth (and even negative growth in some cases) impacted the reasonable opportunity to earn their allowed rates of return and to operate effectively under the existing regulatory model. These problems directly impact the revenue side of the utility financial equation at a time when other issues are impacting the cost side.

Given the average age of utility systems, many assets are at or near the end of their useful physical life. Some assets are also at the end of their useful economic life as new technologies have changed the cost structure of utility service. Aging infrastructure creates substantial demand for new capital resources to replace the aging infrastructure without new customers or new energy uses to defray the cost of the new infrastructure investment. These non-revenue producing investments in infrastructure increase utility rates at the same time new DER technology, conservation and energy efficiency create additional reductions in revenues. Infrastructure investments are also needed to meet new operating requirements resulting from new environmental regulations and other new regulations; such as Order 1000 issued by the Federal Energy Regulatory Commission (FERC) dealing with electric transmission planning processes and North American Electric Reliability Corporation (NERC) compliance. The result is that utility rate bases are growing faster than they have since the end of the new plant construction eras of the 1970s and 1980s. This investment growth is occurring during a period when revenue growth is low or non-existent.

There also are new demands for infrastructure to accommodate renewable energy resources on the distribution grid and to develop new renewable energy products. The infrastructure investments for renewable resources range from the new utility scale renewable energy sources; new transmission facilities to deliver renewable energy from remote areas to load centers: distribution system upgrades to accommodate DER; and developing a more efficient mix of generation resources to protect the utility's system reliability and stability. As with other infrastructure requirements, these costs challenge the utility to recover new investments through rates: (1) without the addition of new loads; (2) with DER creating lower kWh loads, but without an equivalent decrease in the utility's peak loads; and (3) with no change in the peak loads on transmission and distribution for some utilities.

One final issue that represents a large investment to safeguard the utilities infrastructure is cyber security. The types of costs associated with cyber security range from hardware and software costs to operating expenses for data collection and analysis. Today's utility operations are highly dependent on integrated systems to manage complex network resources in order to capture data, as well as to deliver, bill and service millions of customers. New emphasis is being placed on information related to the operation of the distribution grid. The need to protect all assets, components and data within a finite physical and logical boundary is critical to the daily operations of every utility. Cyber security requirements are based on Critical Infrastructure Protection (CIP) regulations issued by the FERC and managed through the NERC. These regulations and the administration of the regulations is a constantly evolving process. This adds cost directly to both capital and expense as utilities create and implement solutions to meet and maintain the security of their infrastructure.

Each of these issues represents a new business challenge for electric utilities as they seek to operate efficiently, reliably and cost-effectively in this new operating environment. At the same time, utilities have new operational challenges in an environment with substantial growth in DER creating a new and significant class of "partial requirements service customers" who do not use the system in the same historical way.

THE NEED FOR CHANGES TO TRADITIONAL UTILITY RATEMAKING PRACTICES

Each of these issues also directly impacts the following utility ratemaking practices:

- The regulatory compact;
- Test year determination for setting rates;
- Treatment of volatile cost elements that are not subject to meaningful control by the utility and cannot reasonably be matched with corresponding revenues when rates are set only through a traditional historic based test year in a rate case consistently biasing a utility's earnings above or below its allowed return; and
- Treatment of unpredictable, uncertain, recurring, and material cost elements included in the utility's revenue requirement.

As discussed in detail below, the regulatory compact describes the system of legal rights and obligations of the utility and state public utility commissions that define the environment in which utility ratemaking occurs. The regulatory compact protects the interests of various stakeholder groups including a utility's customers and investors. The issues that are fundamentally changing the utility business model require that regulatory policies, and potential legislative mandates, change with the changing business model to assure safe, reliable and cost-effective utility services are provided to customers at compensatory rates. The alternative regulatory mechanisms required by these industry changes protect the core regulatory compact in a new environment. Importantly, the changes in the regulatory environment are critical for meeting requirements related to just and reasonable rates that provide the utility a reasonable opportunity to earn the allowed return.

The historical test year is only legitimate to the degree it acts as a reasonable indicator of future revenues and expenses. With slow customer growth and little or negative sales growth, it is important that the utility's test year revenue projections portray a reasonable expectation of future revenues. Likewise, the additional infrastructure investment occurring annually together with other expense items should be estimated consistent with the future period during which rates are effective. This suggests that attention should be given to the ability of the selected test year to properly reflect costs if regulation is to provide the utility with a reasonable opportunity to earn its allowed rate of return. Reexamination of the test year concept will be a necessary element of any review of the utility regulatory model, and is discussed below.

Historical costs are only a good prediction of future costs when the costs are not subject to volatility or a systematic bias (upward or downward) as the result of inflation or other cost drivers. To understand the upward bias of costs, it is only necessary to understand that the costs of new facilities are substantially higher than the cost basis for a utility's rates – which is historical, embedded costs less accumulated depreciation. Effective utility regulation recognizes the need to allow for adjustments to expenses that occur outside the reasonable control of utility management particularly when those changes threaten the reasonable opportunity to earn the authorized return set by the utility regulator. These exogenous cost changes may represent both increases and decreases in the utility's total revenue requirement. Utilities should not profit from, or be denied recovery of, cost changes that are beyond management's control.

Regulatory control of the utility industry has existed for over a century. During that time, utility regulators have faced changes in the entities they regulate and the environment in which those entities operate. As a result, there are now many more ratemaking practices to support utility regulation implemented to address the changing environment. Both federal and state ratemaking have evolved to address the types of issues faced today with models from telecommunications, railroads, pipelines (both natural gas and liquids), water, and so forth. These models have explicitly addressed changes in the determination of test years, the design of utility rates, the widespread adoption of adjustment clauses, and other innovative ways to enhance cash flow in the face of utilities' growing rate base requirements.

A utility's test year has evolved from a fully historical basis to a fully forecasted basis, and all variations in between depending on the particular state or federal jurisdiction. Some utility regulators have recognized the value of setting rates for more than one year based on multiple test years, or have utilized formula rates that are reset annually. Formula rates may be based on actual costs or on a price or revenue cap formula in the case of Performance-Based Regulation (PBR). There are different ways of determining the revenue requirements including alternative rate base treatments. For example, some regulators permit Construction Work in Progress (CWIP) in rate base to improve cash flow and to reduce the future cost of plant in the utility's rate base. The FERC has adopted trended original cost for determining the rate base of oil pipelines. Some regulators allow for adjustment clause formulas to adjust rate base between rate cases to reflect the impact of infrastructure capital additions made pursuant to approved, long-term infrastructure replacement plans. These types of tools have been used to address some of the critical issues related to the test year concept.

Rate structure modifications such as rate adjustment mechanisms (RAMs), trackers and formula rates are being used to provide utilities with more reasonable opportunities to earn their allowed rates of return. Rates are being restructured to accommodate a mixed monopoly/competitive model. Rates have been developed to recover costs from customers who purchase only some portions of the utilities' services. These partial requirements customers may need services such as supplemental service or standby service with inherently different load shapes compared to the former full requirements load. The use of adjustment clauses has become a universal tool as part of the rate design process to improve the matching of cost and revenues. These tools exist and are used under all forms of cost of service regulation from traditional cost of service regulatory models to alternative regulatory models such as PBR and formula rates.

RAMs go well beyond the typical fuel and purchased power adjustment clauses and address revenue stabilization through weather adjustment clauses, revenue decoupling adjustments, and formula-based mechanisms designed to adjust rates to accommodate unforeseen cost changes between utility rate cases. Adjustment clauses have been designed to recover costs associated with both capital and expense components. For example, some adjustment clauses recover environmental costs including both a capital component and the variable cost of chemicals where those costs are not already recoverable through the utility's fuel adjustment clause. With the advent of RTOs or ISOs, regulators authorized adjustment clauses to pass through federally approved transmission costs based on formula rates and with the new FERC policy statement permitting gas pipelines to establish mechanisms to recover infrastructure replacement costs likely for gas transmission as well. The importance of these adjustment clauses differs from utility to utility since not every utility has the same operating circumstances.

The important point is that each utility must have the regulatory tools in place to ensure a reasonable opportunity to earn its authorized return on equity given the circumstances unique to its service territory and its operating environment. The regulatory tools will be unique even for utilities operating in the same jurisdiction. Each utility will face its own combination of factors that drive the fundamental requirements embodied in the regulatory compact. In each case, the fundamental objectives of just, reasonable and non-discriminatory rates must be satisfied by the public utility commission and that judgment must be safeguarded in a rapidly changing cost-environment to ensure the regulatory compact functions as constitutionally required.

The remainder of this report will discuss useful regulatory tools in accommodating the business challenges caused by the fast evolving energy industry environment.

The Regulatory Compact and its Role in Modernizing Utility Ratemaking

The concept of the regulatory compact is often discussed in the context of regulatory policy decisions. Despite the widespread use of the term, it has not been broadly used in the academic literature related to utility regulation. In our view the regulatory compact represents a shorthand reference to the system of obligations and rights that underlie the regulatory process. These rights and obligations result from the legislative and judicial processes as they relate to utility regulation and are administered through the regulatory process. Our aim is to provide an overview of the elements of the regulatory compact as a basis for assuring safe, reliable and cost effective utility service in the ever changing economic environment facing energy utilities today.

The foundation of the regulatory compact is the system of utility obligations and rights that can be summarized as follows:

Figure 1 Summary of the Regulatory Compact

UTILITY OBLIGATIONS	UTILITY RIGHTS
Obligation to Serve	Right to a Reasonable Rate of Return
Safe and Reliable Service	Service Subject to Reasonable Rates, Rules, and Regulations
Non-Discriminatory Rates	Protection from Competition
Just and Reasonable Rates	Eminent Domain

Both the obligations and rights are constrained by the regulatory process. Thus, there is no unlimited obligation to serve, but rather an obligation constrained by a variety of legislative and regulatory policies such as line extension rules, policies related to payment, and so forth. Similarly, the utility's right to a reasonable rate of return is constrained to a return on assets that are considered to be used and useful, and whose costs have been prudently incurred. The list of constraints on the regulatory compact for both obligations and rights requires an in-depth analysis of statutory issues and judicial decisions that have interpreted their statutory meanings. It is not the purpose of this discussion to provide an opinion on these legal issues, but rather to note specific aspects of the regulatory compact as they impact the utility ratemaking process with the changing energy market.

In Black & Veatch's view, the fundamental shift occurring in the utility business model occasioned by the issues previously discussed has created a new model of mixed monopoly and competition as the result of the small scale implementation of DER. This trend has become a major factor in the need for new utility regulatory models. Nevertheless, these new models must continue to meet the requirements of providing the utility with a reasonable opportunity to earn its allowed rate of return.

Put another way, the regulatory obligation must still provide the utility with timely cost recovery. That is, the regulatory process should set rates as close as practical to the costs expected to be incurred in the period rates are to be effective. There are several implications for matching revenues and costs. First, for costs that are beyond the control of the utility, there should be the availability of cost tracking mechanisms. Second, for planned rate base additions that are part of a multi-year capital investment plan (such as infrastructure replacement), utility regulators should provide a method for cost recovery between rate cases for these approved plant additions. This should not be in the form of a blank check, but should consist of a carefully reviewed process to assure that new facilities are consistent with the approved plan, and that the costs are prudent. Third, the regulatory process should recognize that the utility must have a reasonable opportunity to actually earn its allowed rate of return. Failure to provide an opportunity to earn the allowed return will result in further detriment to the financial health of the utility even if the approved rate of return equaled the market-based return. Simply, investors respond not to the allowed return but to the return actually earned by the utility. By improving the utility's actual financial performance, regulators ensure that the costs for customers will be lower in the future as the result of lower capital costs over the life of the assets and lower regulatory costs from the prospect of less frequent rate proceedings.

Maintaining balance in the regulatory compact given the economic environment necessitates the regulatory tools and processes for utilities and regulators that assure full recovery of prudently incurred investments and operating costs that are deemed to be used and useful, and that provides a reasonable opportunity to recover prudent and efficient operating costs. This recovery of operating costs must recognize that certain costs can only be fully recoverable on a reasonable basis when the costs are recovered through adjustment clause or cost tracking mechanism used in some jurisdictions that permit automatic recovery of the tracked costs. Properly designed RAMs assure all parties that no more or no less than actual costs are recovered and those recoveries precisely match the portion of costs excluded from base rates as part of the underlying adjustment formula.

To find the balance necessary in the regulatory compact to provide returns for utility investors consistent with the financial marketplace and to protect the interests of customers from excessive rates requires a careful balancing of interests. There is always a danger that the economic environment will disrupt the regulator's careful balancing of interests. The symptoms of this imbalance are more frequent (even annual in some cases) rate cases to correct for the utility's chronic under-earning of its allowed rate of return. Persistent over-earning would also be a symptom of this imbalance. There may be reasons that over or under earnings occur related to a systemic bias in the utility's revenue requirement formula. Addressing any systematic bias is a prerequisite to restoring the balance established by the regulator as part of the regulatory compact.

The Ratemaking Formula: A Fundamental Building Block

The fundamental ratemaking formula is deceptively easy to understand, but much more difficult to implement. The formula is as follows:

$$RR_t = O_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

- RR_t = Revenue Requirement for test period t
- O_t = Operating Expenses for test period t
- M_t = Maintenance Expenses for test period t
- D_t = Depreciation Expenses for test period t
- T_t = Taxes for test period t
- GP_t = Gross Plant for test period t
- AD_t = Accumulated Depreciation for test period t
- ORB_t = Other Rate Base for test period t
- ROR_t = Rate of Return for test period t.

This equation and its components will be used to discuss various issues in the following section and will be referred to as the test year ratemaking formula.

The test year ratemaking formula seems simple enough. Yet, issues typically are raised in utility rate cases relative to every element of the formula. There are issues on the determination of the test year; the level of expenses to be included in base rates; what adjustments, if any, should be made to the test year; the determination of depreciation expense and taxes; the level of gross plant to be used in the determination of rate base; the determination of accumulated depreciation; the definition of the other rate base items that may be either positive or negative values; and the rate of return on rate base that includes the appropriate capital structure and the cost of each component of that structure.

TEST YEAR DETERMINATION

The issues associated with test year determination differ among jurisdictions. At its core, the purpose of the test year is to serve as an estimate of what a utility's costs will be to provide service in the *Rate Effective Period* or *Rate Year* so that new rate revenues will exactly match the indicated costs. The concept of the *Rate Year* is the first twelve months after the new rates take effect. Ideally, the relationship can be expressed as follows:

$$RR_t = RR_{t+1}$$

Where:

RR_{t+1} is the Revenue Requirement for the Rate Year.

Ideally, it would also be true that the rate revenues in the Rate Year would equal the actual revenue requirement for that year.

Regardless of the basis for the test year, its purpose is to provide a reasonable estimate of the costs to be incurred and the revenues to be produced in that Rate Year. The efficacy of different forms of the test year concept has evolved over time to reflect the circumstances of the utility. As a result, there are many different forms of the test year. The following alternative definitions of a utility's test year have been used by regulators to estimate the utility's costs in the Rate Year:

- *Historical Test Year* - a 12-month period in which actual costs are known (based on per book amounts) and contained in the utility's accounting records.
- *Normalized Historic Test Year* - a 12-month period in which actual known costs from the accounting records of the utility are normalized for weather or other non-recurring expenses.
- *Normalized and Annualized Test Year* - a 12-month period in which actual known costs are normalized (as described above) and other costs are annualized for changes in costs that occurred in the historic period that result in higher or lower costs when applied over a full 12-month period.
- *Normalized, Annualized and Pro-Forma Test Year* - a 12-month period that is normalized and annualized (as described above) with pro-forma adjustments for changes that have occurred after the end of the test year. Pro-forma adjustments may be known and measurable at some point during the rate case process, or they may be known to occur during the Rate Year.
- *Hybrid Test Year* - a 12-month period of which a part is actual and part is forecast that may or may not be subject to a full true-up during the rate case process.
- *Forecasted Test Year* - a 12-month period that is fully forecasted at the time the utility's rate case is filed. In some forecast test years the forecast may be for the actual Rate Year period, whereas in other cases the forecast is at least partially known and measurable before the Rate Year occurs.

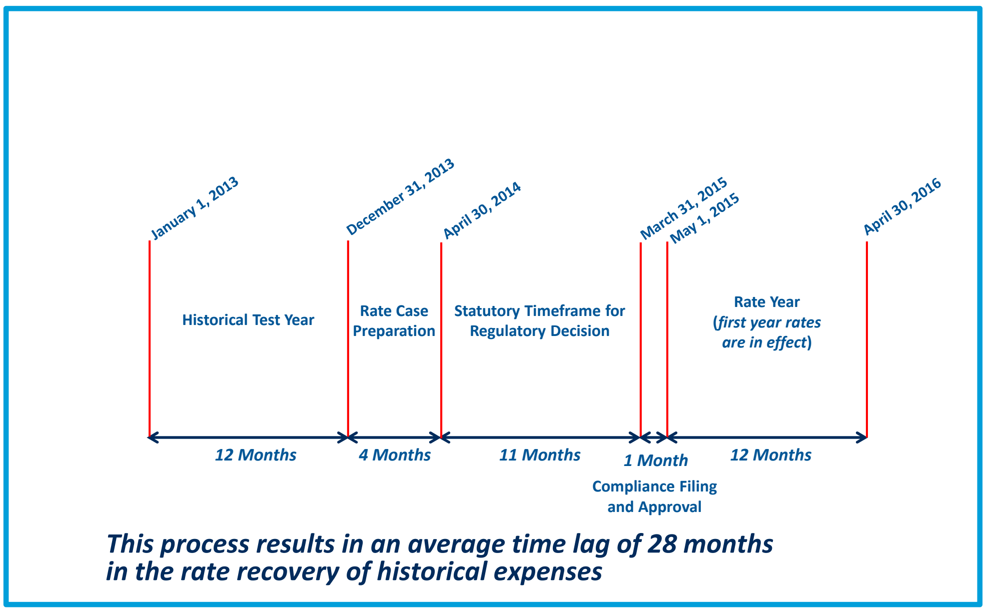
Each of these test years represents fundamentally different assumptions about the costs and revenues in a future Rate Year period. The assumptions used are most easily illustrated with a historic test year. That type of test year assumes that actual costs in the future period will be matched by rates developed on the basis of historical cost data. Essentially, a historic test period assumes that growth in electric load will generate revenues to offset the growth in costs resulting in full cost recovery (including both return of and on the utility's full rate base) in the Rate Year. During the growth period after World War II, this test year alternative produced reasonable outcomes as the combination of technological change and rapid growth permitted declines in nominal rates despite the effects of inflation. In fact, in some years, utility rates actually declined even though the utility's total revenue requirement increased.

Changes such as rapid inflation and rising demand for fuels caused this test year alternative to no longer be a practical choice. New alternatives were created to achieve the desired balance in the regulatory compact. These solutions included adoption of refined formulas for ratemaking where the cost of fuel and purchased power became subject to a different formula that allowed for adjustment to reflect actual cost changes outside of the utility's test period. In addition, both regulators and sometimes legislators also sought alternatives to address cost differences between the test year and rate year. For example, the FERC amended the definition of the test year in 1980 to include the right of a utility to use a forecast test year for the Rate Year. Over the years, a number of state regulatory commissions have adopted the concept of a future test year to allow for matching of costs and revenues in the Rate Year and to provide an opportunity for the utility to earn the allowed return.

THE CONCEPT OF REGULATORY LAG

In its simplest form, regulatory lag is the time between the incurrence of a cost by the utility and when those costs are recovered in rates. As a result, the amount of regulatory lag that a utility experiences is impacted by how the test year is defined in the utility's rate case and the timing of regulatory decisions in those rate cases. The factors impacting the level of regulatory lag are illustrated below.

Figure 2 Illustrative Example of Regulatory Lag



Regulatory lag is measured from the utility's test year to the rate year and is expressed in months. The time lag is also a function of some of the elements of the test year. For example, if rate base is determined as a thirteen month average of net plant, the regulatory lag as calculated above would be six months longer than if rate base was determined at the end of the test year adjusted for known and measurable adjustments beyond the test year. Essentially, the historical test year becomes "stale" relative to actual conditions in the Rate Year as the test year is further lagged from the Rate Year. Mathematically, the relationship between the Test Year and the Rate Year is a biased estimate of costs given by the equation (during periods of rising costs):

$$RR_{t} < RR_{t+1}$$

The result of this bias for a utility is to consistently earn rates of return lower than the allowed rate of return (on a weather normalized, test year basis). This is the most likely result of using an historical test year in any form.

While it is theoretically possible, of course, for regulatory lag to result in a bias for a utility to consistently earn rates of return higher than the allowed return, given the environment in which utilities currently operate as discussed in this paper, that phenomenon is not expected to occur in the foreseeable future. Periodic general rate case filings would provide ample opportunity for regulatory authorities to become aware of such a consistent bias should it come to pass.

EARNINGS ATTRITION

Regulatory lag results in earnings attrition when there is general inflation. Earnings attrition is the deterioration of a utility's actual rate of return on equity below its allowed rate of return on equity that occurs when the relationship between revenues, costs, and rate base used to establish rates (i.e., using a historical test year) have changed by the time rates go into effect. For example, if external factors are driving costs to increase more than revenues, then the rate of return will fall short of the allowed return, even if the utility is operating efficiently. Similarly, when growth in the utility's investment outstrips the rate base used in its test year, the earned rate of return will fall below the allowed return through no fault of the utility's management.

Regulatory lag also results in earnings attrition when the rate of capital additions (infrastructure replacement, growth capital and compliance capital investments) exceeds the annual level depreciation expense because under these conditions rate base grows and will be higher than the rate base level used to set rates. Earnings attrition also results from growth in expenses that depress earnings with fixed rates that cannot reflect cost changes. Attrition may result from both the cost and revenue side of the utility ratemaking process. The concept of attrition is the ultimate reason that regulation must address the issues related to the test year determination.

Since customer usage impacts earnings attrition as well, the low growth or no growth (and in some cases even negative growth) in revenues currently being experienced no longer provides a cushion for mitigating the issue of regulatory lag sufficient to prevent earnings from consistently falling below the allowed level. Additionally, regulatory lag has a more severe impact on efficient utilities than it does on inefficient utilities. This means that utilities that operate efficiently see reduced earnings simply because they have exhausted economically efficient productivity improvements. Less efficient utilities have more opportunities to save costs because of improved productivity and would likely have better earnings than efficient utilities in the face of regulatory lag. This is the opposite of the result that should occur under the regulatory model where efficient utilities should see higher returns for efficiency.

THE PRINCIPLE OF MATCHING COSTS AND REVENUES

An essential element of sound ratemaking is the principle of matching costs and revenues. Under this "matching principle", the utility's customers are charged with the costs of producing the service they receive. Without this principle, current customers would not be paying for the costs they cause the utility to incur. This is particularly important when evaluating costs that are uncontrollable, variable, unpredictable, and recurring. For costs that meet these criteria the test year revenue requirements equation compared to the rate year above may be expressed as follows:

$$RR_{t} \neq RR_{t+1}$$

As an inequality, there is no matching possible of costs and revenues. The absence of matching results from a test period that cannot be the basis for a reliable forecast of the rate year. In fact, in order to provide for a matching principle, certain costs must be treated separately from the utility's base revenue requirement. These costs, instead of being determined based on a test year, are established based on a formula independent of the test year revenue requirements formula. Although the costs are set under a separate formula, the ultimate recovery of those costs adheres to the matching principle and results in much more efficient cost recovery from the customers who cause those costs. The adoption of separate formulas for recovery of costs is fully consistent with the comprehensive rate case determination of the costs to be incurred in the Rate Year. Thus, the combination of formula based costs and test year determined costs in the rate case preserves the regulatory lag incentive for costs that management can control and costs that are reasonably projected by the historic test period. Properly designed formulas are an essential part of the test year cost determination. Importantly, the use of formulas as part of the revenue requirement determination meets all the tests of just and reasonable rates and providing the utility an opportunity to earn its allowed rate of return. The principle of matching costs and revenues in the rate year occurs only when historic test years are coupled with full tracking RAMs for costs such as fuel and purchased power which cannot be reasonably projected based on the results in a historic test period.

It is also important to note that the failure to match costs and revenues does not meet policy goals such as rate efficiency and the creation of appropriate price signals. Absent tools to mitigate cost mismatches between the test year and the rate year, both investors and customers are impacted negatively. The ultimate result from a continued mismatch of costs and revenues is either higher bills for customers in the near-term when revenues exceed costs, or higher bills for customers in the long-term when revenues are less than costs. The first result is obvious because when a utility over earns, it is the customer who has paid more than necessary. The second result is less obvious but nevertheless is a real outcome. Higher bills result over time as the utility's cost of capital rises and as the utility chases revenues through more frequent and administratively costly rate cases. Failure to match costs and revenues may also have the effect of signaling customers to use more utility service because bills are lower than the actual cost to provide the service. To the extent that better price signals provide customers with the proper information to make better energy choices, the economy is more efficient. The second outcome of matching costs and revenues is the lower long-run cost of service for all classes of customers through lower financing costs for the utility.

The Role of Adjustment Clauses in Utility Regulation

Adjustment clauses represent an important ratemaking practice to provide a utility with the proper matching of costs and revenues consistent with the regulatory principle discussed above. The typical adjustment clause is approved by the regulator so that changes in the costs specified by regulation are reflected in rates as either increases or decreases to the price paid by customers. As such, the adjustment clause becomes part of each rate schedule applicable to the classes of service. The adjustment clause, as a form of formula rate, remains an integral part of the test year revenue requirements determination. However, the adjustment clause allows for an explicit rate adjustment outside of a general rate case in response to a change in the particular cost element for which the adjustment clause is designed.

Returning to the basic revenue requirements formula above, it may be modified as follows for the existence of an adjustment clause (the fuel adjustment clause is used as an example):

$$RR_t = O_t - FC_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

FC_t is the cost of fuel to be removed and recovered through a fuel adjustment clause – which is the most common form of adjustment clause. In this example, the fuel adjustment clause is a separate element of each rate schedule that is comprehensive in that it fully recovers 100% of the prudently incurred costs of providing energy (commodity) to customers and none of those costs are included in base rates. The result is that the cost recovery in the Rate Year is defined as follows:

$$R_{t+1} = RR_t + FC_{t+1}$$

Where:

R_{t+1} is the revenue in the Rate Year and FC_{t+1} is the actual fuel cost incurred by the utility in the Rate Year. The formula for calculating the fuel adjustment clause above is defined in a manner consistent with the costs removed from the operating expense in establishing base rates. For example, the formula for FC_{t+1} might be as simple as referencing the specific accounts to be used in the calculation such as the sum of accounts 501-Fuel, 547-Fuel and 555-Purchased Power Expense. Typically, a fuel adjustment clause is much more comprehensive than the simple version and includes a variety of other variable costs associated with the production of energy. Each fuel clause is likely to be different based on the volatility of costs associated with power production or other operating considerations such as being a member of a regional power coordinating group. The key component is that the formula for the fuel clause matches the costs removed from the test year revenue requirements and provides for full recovery of all prudently incurred costs for the rate year. Absent the full recovery of these prudently incurred expenses, the utility's rates could not be considered just and reasonable under the regulatory standard of full recovery of prudently incurred costs.

FUEL ADJUSTMENT CLAUSES

The provisions for recovery of a utility's fuel costs are defined in detail either specifically for the utility or broadly for all jurisdictional utilities through a standard regulatory rule. For example, the FERC uses a rule codified as 18 CFR 35.14 - Fuel cost and purchased economic power adjustment clauses. This rule specifies the costs to be recovered and the formula to be used to in determining the fuel adjustment. Exhibit 1 provides a copy of the FERC Rule, a Kentucky Public Service Commission rule and several sample adjustment clauses related to fuel and purchased power as well as other types of adjustments. It is important to recognize that in a mixed monopoly/competition model, the fuel adjustment clause must be redesigned as part of the utility's unbundled rate structure. The redesign of the fuel adjustment clause is discussed below.

The first step in developing a modern fuel adjustment clause is to remove all fuel and related costs from the utility's base rates. Fuel costs include fuel, fuel transportation and handling, purchased power, carrying costs on deferred balances; uncollectible fuel cost recovery, variable generating costs such as environmental chemicals, transmission costs and, so forth. Removing the fuel costs from base rates results in more efficient rates for customers by signaling customers when the cost of fuel and purchased power changes, and by allowing for a more accurate reflection of seasonal and Time-of-Use (TOU) cost differences. By removing all fuel costs from base rates, the fuel clause tracks cost causation more accurately by customer voltage level of service, by season and, where appropriate, by on-peak and off-peak periods. The resulting cost-based price signals promote economic efficiency. The customer's bill is now properly unbundled because all of the variable production costs are reflected in the separate fuel rate. This gives the customer the ability to clearly understand how the utility's costs of power change by season and by the times when power is used – as well as when the changing market conditions affect the cost of fuel and purchased power.

Finally, placing all such costs into the fuel clause permits easier review by the utility, regulatory, and other interested parties. The resulting change means that the utility will be able to recover its fuel costs on a more accurate and timely basis throughout the year and to adjust the seasonal charges when significant fuel cost or market changes occur.

The second step in modernizing the fuel adjustment clause is to determine if costs vary by season or time of use and, if so, to which classes such variations should apply. When costs differ significantly from one season to another during the year, it is appropriate to reflect those differences for all customer classes since there is no need to change meters to bill seasonally differentiated costs. This is referred to in utility ratemaking as the "seasonal differential." The seasonal differential recognizes that system operating conditions and, therefore, marginal costs may differ in a predictable pattern that needs to be reflected in rates to improve efficiency and economic price signals. There are a number of reasons for cost differences to arise based on seasons of the year.

The appropriate costs to analyze are marginal costs – costs affected by changing demand ("Megawatts" or "MW") and energy ("Megawatt hours" or "MWH"). By contrast, average embedded costs do not change with changes in load, and are sunk costs by definition. The existence of seasonal cost differences is most often driven by the utility's mix of fuels used to produce energy to meet the peak demands of the system, as well as the intensity of those peak demands. In addition, as load on the system increases, the marginal costs for a given generation unit also change based on the heat rate curve of the unit. The heat rate curve shows the relationship between the fuel input per unit of rated-load and the output per unit of rated-load. The heat rate curve can show when and if changes in marginal costs are significant. Where the maximum demand on capacity of the system differs significantly from one month to another, there may also be seasonal capacity cost differentials. But one must recognize that demand on the system also includes scheduled outages, unit de-ratings and unit forced outages – in addition to customer load. These other factors generally represent a smaller total impact than load, but must also be considered in evaluating seasonal differentials related to a capacity cost component.

The practical requirements of utility systems associated with the other demands on capacity cause a leveling of the total system demands. For example, a system may be winter peaking for load, but summer peaking for reliability, because of lower capacity ratings of generators in the summer. High load factor systems may find that the total demand on capacity resources is the same year round because of the need to schedule plant maintenance in the spring and fall. By analyzing the cost patterns, it is possible to determine if seasonal and TOU rates provide better price signals and if the magnitude of the price differentials warrant reflection in rates.

Most utilities are members of a wholesale market ("Market") and, therefore, the marginal cost is not driven solely by the resources of the utility. This occurs because the utility operates to minimize the cost of power delivered to customers. The utility will purchase power from the Market at times when power from the Market is less expensive than that from running its own generation resources. In this case, marginal cost for the utility in any hour depends not only on its own generation but on generation in the interconnected Market. Essentially, utility marginal cost is based on the lower of its own marginal costs or the Market's marginal cost. The net result is that the analysis of marginal cost for a utility depends on much more than the utility system and is impacted by factors such as unit availability and transmission loading for a much larger and more diverse set of generation resources than owned by the utility. All of these characteristics are best reflected in an unbundled fuel adjustment clause. The unbundled fuel adjustment clause is also a key element in promoting conservation, DSM and DG.

Finally, the rationale for a fuel adjustment clause is not merely about the volatility of input prices such as the cost of coal or natural gas; it is about the volatility of the total costs of fuel and level of sales that make the unit cost of fuel volatile. For example, weather may impact the cost and sales and significantly change the unit costs of fuel because of the changes resulting from plants operating at different points on the heat rate curve, from different fuel mix or from different levels and prices for off-system sales. The end result is a different cost per kWh than would have been calculated on a weather normalized test year basis.

OTHER TYPES OF ADJUSTMENT CLAUSES

While fuel cost adjustment clauses are the most common type of adjustment clause in the utility industry, there are other adjustment clauses designed to match costs and revenues during the rate year for costs that are volatile, unpredictable or highly uncertain and beyond the reasonable control of the utility management.

Each type of adjustment clause is based on a formula approved either in a rate case or a separate proceeding for establishing cost recovery independent of current rate levels. Adjustment clauses take one of two general forms: (1) a comprehensive adjustment clause designed to separately recover all of the costs subject to the clause (none of which are included in base rates) as shown in the equation above for the full tracking fuel adjustment clause; or (2) an adjustment clause may be an incremental adjustment clause recovering (or returning as the case may be) changes from cost levels included in base rates as given by the following equation:

$$RR_t = XFO\ t + BFC_t + M_t + D_t + T_t + (GP_t - AD_t + ORB_t) * ROR_t$$

Where:

XFO_t is the operating cost in the test year (less the base fuel costs in the test year) and BFC_t is the base fuel cost established in the test year. The revenue recovery in the rate year is given by the following equation:

$$R_{t+1} = RR_t - (BFC_t - FC_{t+1})$$

Each of these formulas is based on the assumption of a perfect match in costs and revenues for the fuel adjustment clause for illustrative purposes. Practically, there would also be a reconciliation account for fuel costs to ensure that costs and revenues match over time based on the actual results.

Adjustment clauses are designed to allow the utility to adjust its rates to recover in a timely fashion cost changes for significant expense items or for items where the utility has little or no control over the costs. The adjustment clause seeks to mitigate the impact of volatile or uncertain costs that are otherwise prudently incurred on the utility's ability to earn its allowed rate of return. Essentially, an adjustment clause should match costs dollar for dollar in the rate year so as to avoid either windfall gains or losses in the return component of the utility's revenue requirement. The end result of a properly designed adjustment clause is to have rates that more closely match the rate year cost of service. A key point in reviewing the concept of an adjustment clause is that the utility does not earn any more or less as a result of the operation of the adjustment clause. The utility only has an opportunity to earn its allowed rate of return consistent with prudent management of the costs that it must incur to serve customers in the rate year.

To emphasize, the use of adjustment clauses is an important and significant practice in providing the utility with a reasonable opportunity to earn its allowed rate of return by allowing timely recovery of prudently incurred costs. Without the existence of adjustment clauses, utilities would be faced with more volatile earnings based on factors beyond management's control. The regulatory lag issue creates an unreasonable barrier to earning the allowed rate of return. This earnings volatility impacts not only shareholders but also all customer classes. When cost recovery is inadequate, the utility's cost of capital increases. Higher borrowing and equity costs have a large impact on customers because of the capital intensity of the utility industry. As a general proposition, customers are always better off if regulators mitigate earnings volatility rather than to leave earnings volatility unmitigated and fairly compensate the utility for that volatility. The reason is simple. When revenues and earnings are volatile, utilities adjust the costs they can control (including the elimination of discretionary capital expenditures from which customers would otherwise benefit) to minimize that volatility. These adjustments could impact reliability, service quality and the financial flexibility of the utility. Importantly, providing a reasonable opportunity to earn the allowed rate of return on an annual basis will result in lower long-run costs for customers as the result of lower capital costs and the administering of less frequent rate cases. Proper recognition of the lower costs as it relates to the equity return in modern utility regulation only requires that the comparable companies operate under a RAM similar to that of the utility requesting the adjustment.[3]

As noted above, there are different types of adjustment clauses approved for utilities in the U.S. Figure 3 below provides a partial list of these adjustment clauses. As the list indicates, there are numerous adjustment clauses in use for different utilities based on the circumstances each utility faces and the ability of the rate case process to address timely cost and revenue matching for specific identifiable costs subject to review and periodic true-up. As a practical matter, the variety of adjustment clauses recognizes the importance of a proper understanding of the components of the utility revenue requirement formula and the ability of those cost components to provide a reasonable estimate of the actual rate year cost of service. Each adjustment clause reflects either full tracking of costs not otherwise included in the utility's base rates or smaller incremental adjustments for cost elements that cannot be reasonably determined using historic period data as the basis for a future period estimate of costs.

Figure 3 Types of Adjustment Clauses Approved for Utilities in the U.S.

ADJUSTMENT CLAUSE DESCRIPTION	
Fuel and Purchased Power	Vegetation Management
Infrastructure Cost	Revenue Decoupling
Transmission Cost	Smart Grid/AMI Costs
Environmental Cost	Property Taxes
Renewable Energy Cost	Pension/OPEB Costs
DSM/EE Cost	Bad Debt/Uncollectible Expense
Annual Cost of Capital	Weather Normalization
Nuclear Construction Cost	Bill Stabilization
Transmission Costs for ISO/RTO Charges	Construction Work in Progress (CWIP)

The large number of different adjustment clauses reflects a trend both legislatively and in regulatory proceedings to acknowledge that numerous changes occurring in the utility business environment l have significant, uncontrollable and unpredictable impacts on the utility. These impacts, if left un-addressed, can have negative financial consequences for utilities and long-run implications for higher cost and a decrease in the quality of utility service. Infrastructure cost adjustment clauses represent a good example of the trend. For many of the growth years of the utility industry, the issue of replacing (including retrofits of) infrastructure was far less of an issue for two reasons. First, there was not a great amount of infrastructure that needed to be replaced and when replacement was required, it usually was part of the business solution for serving the utility's growing customer base. The replacement also generated revenue from this customer growth to help pay for the replacement

[3] As a practical matter, for a fuel adjustment clause there is a virtual certainty that comparable companies will have an FAC or the equivalent so the market return will already be adjusted to reflect the lower capital costs associated with and FAC.

assets. The second reason is that the replacement typically reduced costs because it was a better technology and provided services more efficiently.

Today, the electric utility industry's low or no growth in customers and load generate little or no additional revenues to support replacement. Even though the replacement may be more efficient, the costs savings cannot come close to paying for the assets because of the substantial impacts of inflation on capital costs for the new assets. A significant portion of many utility systems have reached a point where replacement is the only option for maintaining a safe and reliable system. In addition, there are far more external influences that impact replacement costs. These may include environmental issues, government policy issues at all levels of government, and regulatory or other government mandates.

The widespread acceptance of adjustment clauses has resulted from one of several specific utility requirements. These requirements include the costs incurred by the utility to:

- Meet government mandates;
- Respond to exogenous factors such as changing accounting standards or NERC standards;
- Accommodate the changing market model by changing the distribution system from a pure energy delivery to a delivery and generation interface; and
- Implement revenue or margin decoupling approaches to make the utility indifferent to load growth or conservation, to stabilize earnings, or to reflect changes in revenue requirements through a pre-established formula.

Some adjustment clauses have been in effect for select utilities for many years as part of the particular jurisdictional regulatory model. Other adjustment clauses have a more recent history as utilities are transitioning to different business and regulatory models.

With the growing number of adjustment clauses, an important question relates to the standard of regulatory review for adjustment clauses. In other words, how should parties review the results of the utility's application of an adjustment clause? First, it must be recognized that an essential purpose of all adjustment clauses is to match costs and revenues in a timely manner so that the utility has a genuine opportunity to earn its allowed rate of return. The matching principle is an important concept because it often is more important than the nature of the costs themselves that are to be matched with revenues. The infrastructure cost adjustment clause discussed above is not as much about volatile or uncertain costs as it is about a systematic process of permitting cost recovery for a class of investments that would not be matched over time in the traditional rate case process. This traditional process would discourage the utility from systematically renewing its infrastructure as its financial condition between rate cases would deteriorate. The most significant rationale for any adjustment clause is found in the matching principle that leads to timely cost recovery and a reasonable opportunity to earn the allowed rate of return.

The second consideration that supports the concept of an adjustment clause is the good faith business intentions on the part of utility management that must be presumed by the regulator. The precedent for this is found in basic ratemaking where it is not the purpose of regulation to manage the utility. Utility management has an obligation to act prudently in running the business, incurring costs, and in managing the timing of those costs. Utilities go to great lengths to analyze their decisions in a way that demonstrate well-conceived, supportable, and reasonable approaches to the business.

The third consideration relates to prudence upon review of these decisions. Any party should be free to raise the issue of prudence upon a showing calling prudence into doubt relative to the costs recovered by the utility through its adjustment clause. Prudence standards are an important part of the review process related to the timely matching of costs and revenues since imprudent costs should not be included in recovery, and should be promptly refunded to customers through rates if there is a final determination of imprudence.

For the prudence standard to be meaningfully applied, the fourth consideration should be regulatory and public oversight of the utility's actions on a regular and timely basis. This implies that the utility, under the terms of the adjustment clause, should file regular reports with the regulator for review that presents operating results of the adjustment clause. In some cases, these reports are required on a monthly or quarterly basis. The reports are also typically subject to periodic audit by regulatory staff. Audit reports are typically available for review by any interested party. As needed, the operation of the adjustment clause may also be subject to a public hearing process.

The fifth consideration is designed to minimize the potential for dispute among parties about cost recovery. Adjustment clauses should be free from conflict over their interpretation. This requires either a clear and comprehensive regulatory rule or an agreed upon definition of the terms and conditions under which the adjustment clause will operate as part of the utility's tariff. The clause should delineate the costs to be recovered under the adjustment clause with clear definitions for each type of cost to be included. The adjustment clause should be subject to periodic review to make sure that changing market circumstances have not changed the definition of costs to be included in the adjustment clause.

As suggested above, the final consideration for an adjustment clause requires the filing of detailed and auditable cost and revenue reports. The use of full tracking adjustment clauses makes the detailed reporting of costs and revenues associated with the clause more transparent for the audit. The required information for filing should be specified in a regulatory rule or in the applicable tariff for the adjustment clause. This type of detail is typically specified in a regulatory rule since it would apply to multiple utilities within a particular jurisdiction. The regulatory rulemaking may also be required to address a legislative mandate that gave rise to the need for the adjustment clause.

Application of these six principles provides the necessary regulatory oversight and gives credibility to the costs and revenues recovered under the clause. The participation of parties assures that the results of application of the matching principle assure that there is a dollar for dollar matching and that there are no excess cost recoveries to the detriment of the customers.

Utility Ratemaking Practices in Other States

The discussion above identified the trends in the use of adjustment clauses by regulators and utilities in the U.S. There are many different types of regulatory policies and locational circumstances across the states relative to the use of adjustment clauses. At the core of adjustment clauses is the need to match costs and revenues under the prevailing regulatory model and the state of regulatory reform within the particular state.

With respect to the use of fuel adjustment clauses (including purchased power), every state in the U.S. where the utility generates some of its own power requirements has some form of a fuel adjustment clause. There is at least one state where the only regulated electric utility has no generation and, therefore, has only a purchased power adjustment clause. There are also a number of states where competitive markets have been established. In those markets the utility typically has a standard offer service (SOS) or provider of last resort obligation (POLR). In these markets, there is no longer any type of fuel adjustment clause, but the matching principle for the energy costs incurred by the utility to provide SOS or POLR operates on the same principle as a fully tracking, unbundled adjustment clause.

Based on Black & Veatch's review of states where energy deregulation has not been implemented, every utility in these states has some form of fuel adjustment clause except for KCP&L and one other utility in a jurisdiction that is a predominately hydroelectric based generation utility (Washington). States where energy deregulation has been implemented have an adjustment clause that recovers the costs of SOS and POLR. In addition, fuel adjustment clauses are common for non-regulated municipal and cooperative utilities as a means of recovering their fuel and purchased power costs. This also includes some electric cooperatives in the state of Missouri that have power cost adjustment clauses. Schedule 1 provides a listing of each state regulatory commission that permits recovery of a utility's fuel and purchased power costs through the operation of a fuel adjustment clause.

In addition to fuel adjustment clauses, numerous utilities across the U.S. have other types of adjustment clauses in operation. Schedule 2 provides a listing of other adjustment clauses approved by state regulatory commissions. Most regulators allow recovery of environmental-related costs in adjustment clauses. These adjustment clauses differ in that some costs may also be included in the fuel adjustment clause while other costs (including capital costs) are recovered in a separate adjustment clause. About half of the states have some type of infrastructure cost adjustment clause. Some are limited to a specific type of asset such as smart grid/AMI, while others may reflect costs associated with specific plant additions. Some adjustment clauses relate to specific assets classes such as transmission facilities or assets approved for construction by a pre-approved capital investment plan. These adjustment clauses and tracker mechanisms operate in the same manner as the fuel adjustment clause in most cases. The changes in costs, either up or down, are passed through to customers in the Rate Year, or are subject to reconciliation and true-up.

It is also common to find a variety of tax related adjustment clauses. In these adjustment clauses, utilities are able to recover various types of taxes and fees including franchise taxes. Property tax recovery is also a common tax that is recovered under tax adjustment clauses. Full revenue decoupling adjustments are less common than the other types of adjustment clauses.[4] Other states have different regulatory models related to recovering changes in costs from year to year to provide the utility with a reasonable opportunity to earn its allowed rate of return. Examples of this type of program include Rate Stabilization and Equalization (RSE) in Alabama that changes rates annually based on changes in annual costs under a formulaic approach whenever the utility's earned return falls outside of a dead band related to the allowed rate of return. Vermont has an Alternative Regulation Plan (ARP) that allows rates to change annually subject to a base rate price cap and specifically includes adjustments outside the cap for large capital projects, exogenous cost changes and an adjustment to the Return on Equity based on a formula. The Vermont ARP has features of both revenue decoupling and multi-year rate plans.

For transmission cost recovery, nearly half the states have adjustment clauses to recover the costs associated with participation in a Regional Transmission Organization (RTO) or an Independent System Operator (ISO). Transmission cost adjustment clauses have become a recent trend in utility rates based on the FERC approval of RTO/ISO operations in states that are not restructured into competitive retail markets. For states with competitive retail markets, SOS costs are fully recovered by the utility providing the service. These rates are based on nodal pricing and include the transmission costs in rates. For each of these states, a transmission cost recovery adjustment clause is not required. In addition, in jurisdictions where the local utility is its own Balancing Authority (i.e., not a member of an RTO/ISO), transmission costs are allocated between the Open Access Transmission Tariff (OATT) and retail customers on a jurisdictional basis and recovered fully in the utility's base rates. The states that permit transmission cost recovery through an adjustment clause represent most of the remaining states where utilities provide bundled services with an RTO/ISO to coordinate and facilitate a formal wholesale market for power.

Under the terms of these markets, many utilities have formula rates that change annually under FERC regulation and the RTO/ISO charges are also subject to FERC jurisdiction. These costs are essentially all pass-through cost items that are beyond the control of the utility. The costs are also deemed to be prudently incurred because they represent the FERC approved rates for the services provided. These organized markets also have impacts that relate directly to the fuel adjustment clause as well. The markets change both the physical operation of member utilities generation fleet and the marginal cost for the utilities energy requirements. Both of these factors impact the fuel adjustment clause.

Although Black & Veatch has not attempted to identify all of the types of adjustment clauses that are currently in operation in the U.S., it is obvious that adjustment clauses have become an important ratemaking practice for regulators to adopt to provide the utility with a reasonable opportunity to earn its allowed rate of return. A growing number of regulatory and legislative bodies have recognized the need to modernize the regulatory and ratemaking process to accommodate a dynamic and changing business environment. These adjustment clauses are valuable tools to ensure a well-balanced regulatory compact that align the interests of the utility's customers and shareholders.

[4] There are other states where partial revenue decoupling adjustment clauses have been approved (e.g., designed to recover lost revenues related to the utility's DSM/EE programs).

Conclusions and Recommendations

This report has discussed the ratemaking formula used to establish a utility's rates and the concepts of regulatory lag and earnings attrition. As noted previously, the policy of using regulatory lag as an incentive for improved performance by a utility is not a sound regulatory policy since it serves as a blunt tool that effectively punishes all utilities whether or not they are operated efficiently. Since regulation should be structured to provide the right incentives to utilities to manage their businesses in a responsible manner, it is critically important to recognize when the prevailing ratemaking practices detract from this primary objective.

While the traditional ratemaking practices of the past have served the utility industry and customers well, they have fallen short in more recent times to provide the desired balance between a utility's customers and shareholders that is a foundational concept under the regulatory compact. In today's energy marketplace, the ability to recover costs and earn a reasonable rate of return on investment often pits the interests of utility shareholders directly against the interests of consumers who are impacted by increased rates. It is the responsibility of state regulators to balance these competing needs. Yet, some regulators continue to move cautiously on cost recovery and rate requests by utilities as a result of challenging economic conditions that still linger in some parts of the U.S. This cautious approach by regulators often conflicts with an industry that recognizes the need to operate efficiently and reliably by investing in new and retrofitted infrastructure. Despite the wider acceptance of regulatory practices that streamline the ratemaking process – as evidenced by the increased use of capital-based adjustment mechanisms – some industry observers still believe that the utilities' interests are favored much less by the regulator than those of the consumer.

This perspective is evidenced in the deteriorating financial health of some utilities that do not have the modernized ratemaking practices described earlier that are designed to address regulatory lag and earnings attrition while enabling utilities to invest wisely in assets which will provide customers with safe, reliable, and cost-effective service, and the new energy choices they desire.

Black & Veatch believes there are a number of ratemaking practices that should be considered for adoption by KCP&L's regulators to restore the balance in the regulatory compact for KCP&L. Specifically, it has become essential that KCP&L should be granted regulatory approval to implement a comprehensive fuel adjustment clause that includes all of the costs for fuel, purchased power, the net effect of off-system sales, and SPP transmission costs associated with power delivery. This adjustment clause should also include the costs of chemicals and other variable costs to meet emission requirements, the cost of any other variable costs of generation, and any charges resulting from SPP for KCP&L's market participation. Ideally, all fuel costs would be recovered in the resulting fuel adjustment charges and removed from KCP&L's base rates so that customers will actually know what portion of their electric bills are for recovery of energy-related costs.

The type of fuel adjustment clause recommended for KCP&L will benefit both its customers and shareholders by assuring that there is a dollar-for-dollar matching of costs and revenues during the Rate Effective Period associated with its current rate case, and during subsequent annual periods. The adoption of a comprehensive fuel adjustment clause together with other ratemaking practices we recommend will reduce, but not eliminate regulatory lag, improve KCP&L's opportunity to earn its allowed rate of return, protect customers from paying higher than actual fuel costs and result in lower long-run costs for its customers. Symmetry in treatment of cost changes either increases or decreases is an important element of a sound RAM or tracker.

In addition to the fuel adjustment clause just described, KCP&L should identify other expenses included in the determination of its revenue requirement that should also be subject to recovery through other adjustment clauses. Besides its fuel adjustment clause (FAC) proposal, KCP&L has identified three other types of potential adjustment mechanisms[5] for which it seeks regulatory approval in its current rate case. Each of the proposed "trackers" is designed to match costs and revenues during the rate year for particular cost elements through a pre-approved deferral accounting process. Trackers represent another ratemaking alternative for matching costs and revenues for earnings purposes, while allowing for the utility's eventual recovery of prudently incurred costs through their amortization in a future rate case. However, unlike an adjustment clause, a tracker as defined by KCP&L makes no adjustment to the utility's actual rates. Instead, it is an accounting mechanism which sets a "baseline" expense level in the utility's current rate case and then "tracks" the difference between the actual expenses incurred by the utility over time (for that cost element) and the baseline amount as a deferred regulatory asset or liability for future recovery or customer credits.[6] The regulatory asset created by the tracker is then considered for recovery in the utility's next general rate case through a multi-year amortization process.

The trackers proposed by KCP&L include: a Property Tax Tracker, a Vegetation Management Tracker, and a Critical Infrastructure and Cyber Security Tracker. Individually and collectively, these ratemaking proposals are consistent with the kinds of adjustment clauses that are being adopted by regulators in other parts of the U.S. to provide for cost matching and to permit utilities to have a reasonable opportunity to earn their allowed rates of return. The difference between KCP&L's proposed tracker concept and an adjustment clause is there is no longer a real time matching of the utility's costs and revenues. Rather, as just described, the deferred accounting treatment creates a regulatory asset or liability over time for later inclusion in rates after a full review and hearing as to the deferred account amounts. As such, KCP&L's tracker concept which ensures that it has an opportunity to fully recover its costs while protecting customers from paying higher than actual costs should be viewed as a very modest change to the way utility rates are traditionally set in Missouri relative to the manner in which an adjustment clause operates.

As noted above, property tax adjustment clauses are in operation in twenty-one (21) states. As with the other adjustment clauses discussed above, there are other regulatory models that permit the utility to adjust rates that would include these costs in the periodic rate adjustments (e.g., RSE in Alabama, attrition adjustments in California, and ARP in Vermont). Thus, even though there is no specific adjustment clause for this cost element in these states, the basic regulatory policy is such that

[5] In its current rate case filing, KCP&L uses the term "tracker" (as distinguished from an adjustment clause) to represent the deferred accounting treatment and eventual rate case recovery of particular expenses that have been approved by the Missouri Public Service Commission for utilities under its jurisdiction. Under this definition, a tracker is distinct from an adjustment clause because rates do not change as costs increase or decrease under a tracker. Rather KCP&L is permitted to defer changes in costs for review and recovery in a subsequent rate case.
[6] Including carrying costs accrued on the deferral account balance.

a matching of costs and revenues is achieved. That type of cost treatment is generally consistent with KCP&L's tracker proposals.

The matching principle is also recognized in the design of the other two trackers proposed by KCP&L. Indeed, for the particular ratemaking mechanism to be efficient, it must accurately match costs dollar-for-dollar subject to subsequent regulatory audit and prudence review. For KCP&L's tracker proposals, that review would occur in the utility's next rate case and would result in the amortization of the approved level of prudently incurred costs through future rates.

The basic point related to adjustment clauses is that some clauses like the fuel adjustment clause have near universal applicability while other clauses have cost elements that are unique to the requesting utility and its operating jurisdiction(s). The conceptual and economic support for adequate cost and revenue matching is compelling. This matching only occurs when the regulatory lag created by the preference for a particular test year (i.e., an historical test year) is minimized and adjustment clauses and trackers are available to track the most volatile components of a utility's costs - the costs that utility management cannot control or costs that cannot be predicted adequately by reference to historic trends.

The combination of utilizing future test years and the responsible application of adjustment clauses and trackers form the basis for modernizing the utility ratemaking process to best accommodate the challenges of a fast changing energy marketplace. The regulatory balance restored through such changes will once again provide KCP&L with a reasonable opportunity to achieve its Commission-allowed return as well as the financial performance expected by its shareholders and to provide customers with safe, reliable, and cost-effective utility service in the years ahead.

Schedules

SCHEDULE 1
Fuel Adjustment Clauses for Electric Utilities by State

STATE REGULATORY COMMISSION	FUEL ADJUSTMENT CLAUSE	RECOVERY OF PURCHASED POWER EXPENSE
Alabama	Yes	Yes
Alaska	Yes	Yes
Arizona	Yes	Yes
Arkansas	Yes	Yes
California	Yes	Yes
Colorado	Yes	Yes
Connecticut	(1)	
Delaware	(1)	
District of Columbia	(1)	
Florida	Yes	Yes
Georgia	Yes	Yes
Hawaii	Yes	Yes
Idaho	Yes	Yes
Illinois	Yes (2)	Yes
Indiana	Yes	Yes
Iowa	Yes	Yes
Kansas	Yes	Yes
Kentucky	Yes	Yes
Louisiana (PSC)	Yes	Yes
Louisiana (New Orleans)	Yes	Yes
Maine	(1)	
Maryland	(1)	
Massachusetts	(1)	
Michigan	Yes	Yes
Minnesota	Yes	Yes
Mississippi	Yes	Yes
Missouri	Yes	Yes
Montana	Yes	Yes
Nebraska	No electric utility regulation	Yes
Nevada	Yes	Yes
New Hampshire	(1)	
New Jersey	(1)	
New Mexico	Yes	Yes
New York	(1)	
North Carolina	Yes	Yes

STATE REGULATORY COMMISSION	FUEL ADJUSTMENT CLAUSE	RECOVERY OF PURCHASED POWER EXPENSE
North Dakota	Yes	Yes
Ohio	(1)	
Oklahoma	Yes	Yes
Oregon	Yes	Yes
Pennsylvania	(1)	
Rhode Island	(1)	
South Carolina	Yes	Yes
South Dakota	Yes	Yes
Tennessee	Yes	Yes
Texas	Yes (2)	Yes
Utah	Yes	Yes
Vermont	Yes	Yes
Virginia	Yes	Yes
Washington	Yes	Yes
West Virginia	Yes	Yes
Wisconsin	Yes	Yes
Wyoming	Yes	Yes

Footnotes:
(1) State with restructured utilities that recover these costs through default utility services
(2) State with a mixture of competitive and default utility services

Source:
SNL/RRA State Profile Data

SCHEDULE 2
Other Adjustment Clauses for Electric Utilities by State

STATE REGULATORY COMMISSION	RECOVERY OF ENVIRONMENTAL COSTS	RECOVERY OF INFRASTRUCTURE COSTS	RECOVERY OF TAX EXPENSE	RECOVERY OF TRANSMISSION EXPENSE	REVENUE DECOUPLING
Alabama	Yes	Yes	Yes	No	No
Alaska	No	No	No	No	No
Arizona	Yes	No	Yes	Yes	Yes
Arkansas	Yes	Yes	Yes	Yes	Yes
California	Yes	No	No	No	Yes
Colorado	Yes	Yes	No	No	Yes
Connecticut	No	No	No	Yes	Yes
Delaware	No	No	No	No	No
District of Columbia	No	Yes	No	No	No
Florida	No	Yes	Yes	No	No
Georgia	Yes	Yes	No	No	No
Hawaii	No	Yes	No	No	Yes
Idaho	No	No	No	No	Yes
Illinois	Yes	No	Yes	Yes	No
Indiana	Yes	No	No	Yes	No
Iowa	Yes	No	Yes	Yes	No
Kansas	Yes	No	Yes	Yes	No
Kentucky	Yes	No	Yes	No	No
Louisiana (PSC)	Yes	No	No	No	No
Louisiana (New Orleans)	Yes	No	No	No	No
Maine	Yes	No	No	No	No
Maryland	Yes	Yes	Yes	No	No
Massachusetts	Yes	Yes	No	Yes	Yes
Michigan	Yes	Yes	No	Yes	No
Minnesota	Yes	No	No	Yes	No
Mississippi	Yes	Yes	No	No	No
Missouri	Yes	No	Yes	No	No
Montana	Yes	No	Yes	No	No
Nevada	Yes	No	No	No	No
New Hampshire	Yes	No	No	Yes	No
New Jersey	Yes	No	Yes	No	No
New Mexico	Yes	No	Yes	No	No
New York	Yes	No	No	No	Yes
North Carolina	Yes	No	No	No	No

STATE REGULATORY COMMISSION	RECOVERY OF ENVIRONMENTAL COSTS	RECOVERY OF INFRASTRUCTURE COSTS	RECOVERY OF TAX EXPENSE	RECOVERY OF TRANSMISSION EXPENSE	REVENUE DECOUPLING
North Dakota	Yes	Yes	No	No	No
Ohio	Yes	Yes	Yes	No	No
Oklahoma	Yes	Yes	Yes	Yes	No
Oregon	Yes	No	No	No	Yes
Pennsylvania	Yes	Yes	Yes	Yes	No
Rhode Island	Yes	Yes	No	No	Yes
South Carolina	Yes	Yes	No	No	No
South Dakota	Yes	Yes	Yes	Yes	No
Tennessee	No	No	No	No	No
Texas	Yes	Yes	Yes	Yes	No
Utah	Yes	No	No	No	No
Vermont	Yes	No	No	No	No
Virginia	Yes	Yes	Yes	Yes	No
Washington	Yes	No	No	No	Yes
West Virginia	Yes	Yes	Yes	Yes	No
Wisconsin	Yes	Yes	Yes	No	No
Wyoming	Yes	Yes	No	No	No

Source:
SNL/RRA State Profile Data

Exhibits

Exhibit 1
Kentucky Fuel Clause

807 KAR 5:056. Fuel adjustment clause.

RELATES TO: KRS Chapter 278
STATUTORY AUTHORITY: KRS 278.030(1)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.030(1) provides that all rates received by an electric utility subject to the jurisdiction of the Public Service Commission shall be fair, just and reasonable. This administrative regulation prescribes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subject to later scrutiny by the Public Service Commission.

Section 1. Fuel Adjustment Clause. Fuel adjustment clauses which are not in conformity with the principles set out below are not in the public interest and may result in suspension of those parts of such rate schedules:

(1) The fuel clause shall provide for periodic adjustment per KWH of sales equal to the difference between the fuel costs per KWH sale in the base period and in the current period according to the following formula:

$$\text{Adjustment Factor} = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F is the expense of fossil fuel in the base (b) and current (m) periods; and S is sales in the base (b) and current (m) periods, all as defined below.

(2) FB/SB shall be so determined that on the effective date of the commission's approval of the utility's application of the formula, the resultant adjustment will be equal to zero.

(3) Fuel costs (F) shall be the most recent actual monthly cost of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(d) The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) All fuel costs shall be based on weighted average inventory costing.

(4) Forced outages are all nonscheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection or acts of the public enemy, then the utility may, upon proper showing, with the approval of the commission, include the fuel cost of substitute energy in the adjustment. Until such approval is obtained, in making the calculations of fuel cost (F) in subsection (3)(a) and (b) of this section the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation.

(5) Sales (S) shall be all KWH's sold, excluding intersystem sales. Where, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of:

(a) Generation;

(b) Purchases;

(c) Interchange-in; less

(d) Energy associated with pumped storage operations; less

(e) Intersystem sales referred to in subsection (3)(d) above; less

(f) Total system losses. Utility used energy shall not be excluded in the determination of sales (S).

(6) The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees.

(7) At the time the fuel clause is initially filed, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the commission and all other agreements, options or similar such documents, and all amendments and modifications thereof related to the procurement of fuel supply and purchased

power. Incorporation by reference is permissible. Any changes in the documents, including price escalations, or any new agreements entered into after the initial submission, shall be submitted at the time they are entered into. Where fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted and the utility shall explain and justify them in writing. Fuel charges which are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause. The commission on its own motion may investigate any aspect of fuel purchasing activities covered by this administrative regulation.

(8) Any tariff filing which contains a fuel clause shall conform that clause with this administrative regulation within three (3) months of the effective date of this administrative regulation. The tariff filing shall contain a description of the fuel clause with detailed cost support.

(9) The monthly fuel adjustment shall be filed with the commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment which shall include data and information as may be required by the commission.

(10) Copies of all documents required to be filed with the commission under this administrative regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

(11) At six (6) month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.

(12) Every two (2) years following the initial effective date of each utility's fuel clause the commission in a public hearing will review and evaluate past operations of the clause, disallow improper expenses and to the extent appropriate reestablish the fuel clause charge in accordance with subsection (2) of this section. (8 Ky.R. 822; eff. 4-7-82.)

Duke Energy Indiana, Inc.
1000 East Main Street
Plainfield, Indiana 46168

IURC No. 14
Forty-third Revised Sheet No. 60
Canceling Forty-second Revised Sheet No. 60

STANDARD CONTRACT RIDER NO. 60
FUEL COST ADJUSTMENT APPLICABLE
TO ALL RETAIL RATE SCHEDULES

A. The applicable charges for electric service to the Company's retail customers shall be increased or decreased, to the nearest 0.001 mill ($0.000001) per kWh to recover and/or credit the cost for fuel in accordance with the following formula:

Fuel Cost Adjustment Factor = F/S - $0.014484

where:

1. "F" is the estimated expense of fuel based on a three-month average cost beginning with the first month of the billing cycle and consisting of the following costs:

   (a) the average cost of fossil fuel consumed due to the operation of Company's own generating units incurred to serve native load customers, including only those items listed in Account 151, of the Federal Energy Regulatory Commisssion's Uniform System of Accounts for Class A and B Public Utilities and Licensees (FERC US of A);

   (b) the actual identifiable fossil and nuclear fuel costs, or, if fuel costs are not specifically identified, costs computed in accordance with applicable Commission Orders, associated with energy purchased or transferred to serve native load customers for reasons other than identified in (c) below;

   (c) the net energy cost, exclusive of capacity or demand charges, of energy purchased or transferred to serve native load customers on an economic dispatch basis, and energy purchased or transferred to serve native load customers resulting from the scheduled outage of a Company owned generating unit, when the costs thereof are less than the Company's fuel costs of replacement net generation from its own system, as computed in accordance with applicable Commission Orders,

2. "S" is the estimated kilowatt-hour sales as recorded on the Company's books and records in accordance with the FERC US of A for the same estimated period set forth in "F,"

B. The factor as computed above shall be modified to allow the recovery of utility receipts taxes and/or other similar revenue based taxes incurred due to the recovery of fuel costs.

C. The factor shall be further modified commencing with the fifth succeeding billing cycle month to reflect the difference between the estimated incremental fuel cost billed and the incremental fuel cost actually incurred during the first and succeeding billing cycle month(s) in which such estimated incremental fuel cost was billed.

D. Effective for all bills rendered beginning with and subsequent to the later of the effective date of the Commission's Order or the first billing cycle of January 2015 the fuel cost adjustment shall be $0.018505 per kilowatt-hour.

E. From time to time, and subject to approval of the Commission, the factor shall be further modified to include the separate recovery, pursuant to Ind. Code 8-1-2-42(a), of costs applicable to certain power purchases in excess of the monthly purchased power benchmark.

ISSUED:

December 30, 2014

EFFECTIVE:

January 2015 - Billing Cycle 1

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 70 - 1B
REPLACES SHEET NO. 70 - 1A
EFFECTIVE DATE 7/15/13

SCHEDULE: FUEL COST ADJUSTMENT RIDER (FA)

AVAILABILITY

This Rider is applicable to and becomes a part of each OCC jurisdictional rate schedule in which reference is made to Fuel Cost Adjustment.

ADJUSTMENT

The Fuel Cost Adjustment shall be calculated by multiplying the total billing kilowatt-hours (kWh) by the Service Level Fuel Cost Adjustment Factor for the current billing period. The Service Level Fuel Cost Adjustment Factor shall be determined on an annual basis and become effective with the November billing cycle in the following manner:

$$FA = \frac{FUEL\$ - EMB\$ + DEF\$}{S}$$

WHERE:

FA = The Service Level Fuel Cost Adjustment Factor (expressed in dollars per kWh) to be applied per kWh consumed.

EMB$ = The amount of fuel cost per kWh embedded in the base rate is 3.4 cents.

DEF$ = The service level prior month's balance sheet amount for the Unrecovered Fuel Cost divided by the service level annual retail kWh sales.

S = Retail service level kWh sales for the period adjusted for any directly assigned fuel expense.

FUEL$= (SYS$ + PP$ - OSEC) x ((S x SLEF)/U) + (GTD$ x SLPDA)

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

APPROVED
AUG 06 2013
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 70 - 2B
REPLACES SHEET NO. 70 - 2A
EFFECTIVE DATE 7/15/13

SCHEDULE: FUEL COST ADJUSTMENT RIDER (FA)

WHERE:

SYS$ = The OCC allowable fuel expense for the period shall be the fuel expense set forth in the FERC Account 5010 and FERC Account 5470. This value will be adjusted for any directly assigned fuel expense associated with these accounts, RTP sales and off-system sales.

PP$ = The energy cost of purchased power for the period shall be the purchased power expense set forth in FERC Account 5550. The purchased power cost shall also include the cost of power purchased from customers, cogeneration and small power production facilities as recorded in FERC Account 5550. This value will be adjusted for any purchased power costs reflected in the OSEC.

OSEC = 75% of the margin from off-system sales of electricity, 75% of the margins from standby service, and 50% of the margins from RTP kWh sales in excess of $0.0015 per net incremental RTP kWh sales booked in the period.

S = Retail service level kWh sales for the period adjusted for any directly assigned fuel expense.

U = Total system service level kWh sales at the generator by the Company for the period adjusted for any directly assigned fuel expense. The OCC jurisdictional amount is defined as OCC jurisdictional kWh sales divided by total company sales exclusive of off-system sales (net system sales).

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	**581748**	**PUD 201000050**
January 29, 2009	**564437**	**PUD 200800144**

APPROVED
AUG 06 2013
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 70 - 3B
REPLACES SHEET NO. 70 - 3A
EFFECTIVE DATE 7/15/13

SCHEDULE: FUEL COST ADJUSTMENT RIDER (FA)

SLEF = The service level expansion factor from the most recent line loss study.

SLPDA= The service level production demand allocator from the test year cost of service study.

GTD$ = The gas transportation and agency expense incurred for the period and is set out in FERC Account 5010.

SUCCESSOR ACCOUNTS AND SUBACCOUNTS

Successor accounts and subaccounts may be included as appropriate following advance notification to the Oklahoma Corporation Commission, Director of Public Utilities.

INTERIM ADJUSTMENT OF FUEL COST ADJUSTMENT FACTOR

In the event that the annual cost of fuel begins to differ significantly from the cost used in the annual fuel cost adjustment factor or the over/under-recovered balance is $50,000,000 or more, an interim adjustment may be filed. The Director of the Public Utility Division shall approve the requested change effective with the first billing cycle of the month subsequent to the approval.

APPROVED
AUG 06 2013
DIRECTOR OF PUBLIC UTILITY

Supplemental Page

Fuel Cost Adjustment Factors

Public Service Company of Oklahoma

Fuel Cost Adjustment Factors ($/kWh)

Period	Service Level 1	Service Level 2	Service Level 3	Service Level 4/5	Service Level 6
Dec 02 – Feb 03	0.003728	0.005433	0.006697	0.007836	
Mar 03 – May 03	0.011235	0.012404	0.012909	0.015861	
June 03 – Aug 03	0.015371	0.015542	0.015957	0.017454	
Sep 03 – Nov 03	0.007748	0.009556	0.010113	0.011269	
Dec 03 – Feb 04	0.007748	0.009556	0.010113	0.011269	
Mar 04 – May 04	0.010422	0.010662	0.011315	0.012561	
June 04 – Aug 04	0.014366	0.014653	0.015479	0.017091	
Sept 04 – Nov 04	0.014841	0.014739	0.015677	0.017511	
Dec 04 – Jan 05	0.017581	0.018371	0.019341	0.020977	
Feb 05	0.017782	0.018097	0.018935	0.020527	
Mar 05 – May 05	0.012679	0.013641	0.014764	0.014983	0.016727
June 05 – Nov 05	0.004477	0.003947	0.004884	0.006360	0.006594
Dec 05 – Mar 06	0.024047	0.024642	0.025729	0.028643	0.028877
Apr 06 – May 06	0.012135	0.012521	0.014018	0.016218	0.016452
June 06 – May 07	0.006712	0.006546	0.008031	0.010065	0.010299
June 07 – Apr 08	0.005419	0.007192	0.008444	0.010070	0.010304
May 08	0.005419	0.007192	0.008444	0.010070	0.010070
June 08 – Nov 08	0.024398	0.025158	0.026714	0.027786	0.027786
Dec 08 – Jan 09	0.005398	0.005809	0.007176	0.008363	0.008363
Feb 09	0.003424	0.003893	0.005284	0.006218	0.006218
Mar 09 – Apr 09	(0.009739)	(0.009103)	(0.007881)	(0.007653)	(0.007653)
May 09	(0.012574)	(0.012004)	(0.010704)	(0.010599)	(0.010599)
June 09 – Dec 09	(0.014161)	(0.014248)	(0.012931)	(0.012792)	(0.012792)
Jan 10 – Mar 10	(0.021086)	(0.021915)	(0.020036)	(0.016130)	(0.016130)
Apr 10 – May 10	(0.001013)	(0.000737)	0.000263	0.001606	0.001606
June 10 – May 11	(0.003972)	(0.003920)	(0.002308)	(0.000651)	(0.000651)
June 11 – May 12	(0.003419)	(0.003464)	(0.001316)	0.001888	0.001888
June 12 –Feb 13	(0.022249)	(0.022194)	(0.020504)	(0.017696)	(0.017696)
Mar 13 –Oct 13	(0.008476)	(0.008764)	(0.007217)	(0.004760)	(0.004760)
Nov 13 – April 14	(0.012313)	(0.012187)	(0.010884)	(0.008525)	(0.008525)
May 14 – Oct 14	(0.007323)	(0.007117)	(0.005682)	(0.003144)	(0.003144)
Nov 14 – Oct 15	(0.009975)	(0.009970)	(0.008574)	(0.006169)	(0.006169)

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 71
EFFECTIVE DATE 1/31/11

SCHEDULE: TAX ADJUSTMENT RIDER (TA)

AVAILABILITY

This Rider is applicable to and becomes a part of each Oklahoma Corporation Commission jurisdiction rate schedule in which reference is made to Tax Adjustment.

ADJUSTMENT

If there shall be imposed after the effective date of this rate schedule, by Federal, State or other Governmental Authority, any tax, other than income tax, payable by Company upon gross revenue, or upon the production, transmission or sale of electric energy, a proportionate share of such additional tax or taxes shall be added to the monthly bills payable by the customer to reimburse the Company for furnishing electric energy to the customer under the applicable pricing schedule. Reduction likewise shall be made in bills payable by customer for any decrease in any such taxes.

Additionally, any occupation taxes, license taxes, franchise fees, and operating permit fees required for engaging in business with any municipality, or for use of its streets and ways, shall be added to the billing of customers residing within such municipality.

Pursuant to OAC 165:35-27-2 of the Corporation Commission of Oklahoma, any franchise payment (based upon a percent of gross revenue) in excess of 2% required by a franchise or other ordinance approved by the qualified electors of a municipality will be stated, as a separate item, on the bills of those consumers receiving service from the Company within the corporate limits of the municipality exacting said payment.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 72
EFFECTIVE DATE 1/31/11

SCHEDULE: METERING ADJUSTMENT RIDER (MA)

AVAILABILITY

This Rider is applicable to and becomes a part of each Oklahoma Corporation Commission jurisdiction rate schedule in which reference is made to Metering Adjustment.

ADJUSTMENT

The Company will adjust kilowatt-hours (kWh), kilowatts (kW), and kilovolt-amperes reactive (kVAR) for metering located on the high side of a company-owned transformer or for metering located on the low side of a customer-owned or leased transformer. The adjustment shall be calculated by multiplying the recorded metered quantities by *one and one-quarter percent (1.25%).* The adjustment then will be added to or subtracted from, as appropriate, the metered quantities to determine the adjusted metered quantities.

PUBLIC SERVICE COMPANY OF OKLAHOMA **SHEET NO. 73**
P.O. BOX 201 **EFFECTIVE DATE 1/31/11**
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SCHEDULE: REGULATORY ASSESSMENT RIDER (RA)

APPLICABILITY

This Rider applies to all retail monthly customer billings rendered, and shall be included as a part of the customer charge, minimum bill charge or other applicable monthly charge as set out on each individual rate schedule.

COMPUTATION

RA = (A + O/URA) / (AMCB x Y)

WHERE: RA = Rider Amount

A = Annual assessment amount as billed by the Commission pursuant to OAC 165:5-3

O/URA= Over/Under Recovery Amount determined by subtracting the total amount of the assessment collected pursuant to the above formula for the previous July 1 through June 30 period from the total Commission assessment for that fiscal year period

AMCB = Estimated Average Monthly Customer Billings

Y = Twelve months

ADJUSTMENTS TO BILLING

Tax Adjustment

The amount calculated at the above rate is subject to adjustment under the provisions of the Company's Tax Adjustment Rider.

TERMS OF PAYMENT

Monthly bills are due and payable by the due date. Monthly bills unpaid by the due date will be assessed a late payment charge of 1 ½ percent of the total amount due.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

Supplemental Page

Regulatory Assessment Rider Fee

July 2004 – June 2005	$0.11
July 2005 – June 2006	$0.12
July 2006 – June 2007	$0.12
July 2007 – June 2008	$0.15
July 2008 – Dec 2008	$0.15
Jan 2009 – June 2009	$0.17
July 2009 – June 2010	$0.18
July 2010 – June 2011	$0.15
July 2011 – June 2012	$0.16
July 2012 – June 2013	$0.18
July 2013 – June 2014	$0.28
July 2014 – June 2015	$0.25

.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 74-1
EFFECTIVE DATE 1/31/11

SCHEDULE: INTERRUPTIBLE SERVICE PILOT RIDER (ISPR) Amended

AVAILABILITY

This Rider is available only in conjunction with Company's Large Power and Lighting (LPL) rate schedules to Customers who contract for not less than 1000 kW of curtailable power. All provisions of the LPL rate schedules will apply except as modified herein. Service must be taken at one point of delivery and measured through one meter. This Rider is not available for backup power to customer owned generation.

The availability of service under this Rider is subject to the Company, in its sole judgment, having sufficient capacity and fuel to serve the requirements of its other customers and to maintain its spinning reserve**.** The availability of total system curtailable and interruptible kW contracted may be limited by the Company to an amount not to exceed 3% of the projected aggregate Company peak demand. Service is available under this Rider only if the use of such service is of such character that service can be curtailed at any time by Company, following 15 minutes notice by Company to Customer that service must be curtailed, without loss to Customer or damage to property or persons and without adversely affecting the public health, safety, and welfare.

DEFINITION OF TERMS

Total kW: Total kW is defined as the sum of the Firm kW and the Curtailable kW designated by the customer when contracting for service under this Rider and will be used to determine the applicable rate schedule.

Firm kW: Firm kW is defined as that portion of the Total kW that is not subject to curtailment under the terms and conditions of this Rider. The Firm kW will be designated by the Customer when contracting for service under this Rider. In addition, Firm kW may be adjusted annually by the Customer by written request to the Company.

Curtailable kW: Curtailable kW is defined as that portion of the Total kW subject to curtailment by the Company under this Rider. The Curtailable kW will be designated by the Customer when contracting for service. In addition, Curtailable kW may be adjusted annually by the Customer by written request to the Company.

Contract Minimum: The customer’s minimum bill shall not be less than the applicable charge for the contracted demand minimum plus the applicable Fuel and Tax Adjustments and in no event shall the contract demand minimum be less than 1,000 kilowatts.

CONDITIONS OF SERVICE

Customer may choose to have Total kW or some portion thereof designated as Curtailable kW. The amount of Total kW not designated as Firm kW shall constitute Customer's Curtailable kW. Customer's service must be equipped, at Customer's expense, with devices necessary to reduce Total kW during the period of curtailment to Firm kW or below and with metering devices necessary to verify that Total kW is at or below the Firm kW. In addition, the Company may request that the Customer's service be equipped, at Customer's expense, with communication equipment necessary to provide instantaneous load information to Company's designated system operating center.

Company will request curtailment of electric service under this Rider as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, avoiding establishment of a peak demand in excess of 95% of the Company's forecasted peak load for the year, maintaining service integrity in the area, or other situations when reduction in load on the Company's system is warranted. To the extent possible, curtailable loads served under this Rider will be curtailed before any curtailment of firm loads is requested or required.

Requests for curtailment will be made by Company's System Operator via telephonic communication to Customer's designated representative(s). Upon application for service under this Rider, Customer shall designate the representative(s) and provide the telephone number at which they may be reached 24 hours a day. In the event of a curtailment for non-emergency purposes, Company will endeavor to provide notice to Customer at least 30 minutes prior to curtailment. In the event of a curtailment for emergency conditions, Company will attempt to provide as much prior notice as possible but is in no way obligated to give more than 15 minutes notice prior to curtailment. Absence of a designated representative or inability of the Company to communicate with the designated representative because of unanswered telephone, busy telephone, or otherwise, once Company has initiated a telephonic communication to the designated representative, will in no way be regarded as an excuse for failure to comply with a curtailment request. The Company may request the customer to install at Customer's expense electronic equipment necessary for automatic notification of curtailment.

No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.

The Company reserves the right to test and verify the customer’s ability to curtail. Such test will be limited to one curtailment per contract term. Any failure of the customer to comply with a request to curtail energy will entitle the Company to call for one additional test. The Company agrees to notify the customer as to the month in which the test will take place, and will consider avoiding tests on days that may cause a unique hardship to the customer’s overall operation. There shall be neither credits for test curtailments nor charges for failure to curtail during a test.

MONTHLY CHARGES AND CREDITS

Customer's net monthly bill for service provided under this Rider will be calculated in accordance with Company's applicable rate schedule, with the exception that a Curtailable Power Credit will be applied. The Curtailable Power Credit will be determined by applying a Demand Credit to the portion of the average kilowatt load used by the Customer during the 15 minute period of maximum use during the month in excess of the Firm kW. However, the Curtailable Power Credit will not exceed the product of the Demand Credit and the Curtailable kW.

The Demand Credit used to calculate the Monthly Curtailable Power Credit will be:

VOLTAGE LEVEL	**DEMAND CREDIT** **100 hours**	**DEMAND CREDIT** **50 hours**
Primary Service (SL3)	$1.75 kW	$.88 kW
Primary Sub (SL2)	$1.46 kW	$.73 kW
Transmission Service (SL1)	$1.38 kW	$.69 kW

The Company will file updated Curtailable Credits with the Commission annually. The Director of the Public Utility Division will approve the requested Curtailable Credits to become effective with the first billing cycle of the new year. The Curtailable Credits will remain in effect unless a request for updated Curtailable Credits is filed by the Company.

The Curtailable Power Credit applied to the customer's bill for service will be recorded in the Federal Energy Regulatory Commission's Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identity of this amount is preserved.

NON-COMPLIANCE PROVISIONS

Customer understands that service under this Rider is contingent upon Customer's complete and timely compliance with Company's requests for curtailment. If, at any time, Customer fails in whole or in part to implement or maintain any request for curtailment to reduce the Total kW to the Firm kW, the Company may, at its option, elect to cancel, effective immediately, the Customer's eligibility for service under this Rider. Should the Company exercise this option, billing for the current and subsequent eleven (11) months will revert to the LPL rate schedule. In addition, any Curtailable Power Credits received by the Customer during the 11 previous months shall be forfeited and reimbursed with interest to the Company over the six (6) month period following the cancellation of Customer's eligibility for service under this Rider.

LIMITATIONS ON CURTAILMENTS

Curtailments under this Rider are limited as follows:

Daily Limit: No longer than 12 hours in any day, measured from midnight to midnight, except during system emergencies as described below.

Annual Limit: No more than 100 hours in any calendar year.

The only curtailments included in curtailment time limits are those implemented at the request of Company for the purposes described in the "Conditions of Service" above. Extended interruptions resulting from failure of transmission or distribution equipment are not included in curtailment time limits. Curtailment time is measured from the time the Company notifies the Customer via telephonic communication when the period of curtailment will begin to the time that Company notifies Customer via telephonic communication that the period of curtailment will end.

During system emergencies when Company has made public pleas to restrict electric energy usage to essential needs because of an area or statewide shortage of electric power and/or energy, curtailable loads served under this Rider may be curtailed continuously without daily limit until such emergency condition has ended. Such curtailments shall be included in annual curtailment time limits.

Curtailments of less than 15 minutes in duration shall constitute a 15-minute period for inclusion in Curtailable time limits.

TERM OF CONTRACT

This Rider is being offered as an experimental service and may be withdrawn by the Company following written notice to each Customer served under the Rider given at least one year prior to such withdrawal. The obligation of the Customer shall continue for a minimum initial term of one year and continuing thereafter unless canceled by Customer following written notice given at least one year prior to such cancellation.

EMERGENCY CURTAILABLE SERVICE RIDER

This Rider provides the Company the right to call upon the Customer and the Customer the option to curtail load during an Emergency Curtailable Event in which the Company requests load curtailment. Upon each event, the Customer shall have the option to curtail load at their premises and be compensated by the Company as provided below.

AVAILABILITY

Eligible customers must be served under the LPL tariff and have a curtailable of load of not less than 1,000 kW. All provisions of the LPL rate schedules will apply except as modified herein.

MONTHLY CHARGES AND CREDITS

Customer's net monthly bill for service provided under this Rider will be calculated in accordance with Company's applicable rate schedule, with the exception that an Emergency Curtailment Credit will be applied as a line item on the Customer’s bill.

The Emergency Curtailment Credit (ECC) will be quoted to the Customer upon notification of the ECS event and will be based on the anticipated market price at the time of the ECS event. The ECC price will be based on the prevailing market price and the SPP imbalance price. However, if the ECS event was initiated due to a localized constraint, PSO reserves the right to increase the ECR price to the level appropriate to ensure an adequate response is obtained.

The ECC applied to the customer’s bill for service will be recorded in the Federal Energy Regulatory Commission’s Uniform System of Accounts under Account 555, Purchased Power, and will be recorded in a subaccount so that the separate identity of this amount is preserved.

DEFINITION OF TERMS

Emergency Curtailable Event: Company may call for curtailment in the event the Southwest Power Pool (SPP) has declared an emergency, in the events loads are forecasted to be at 5% of reserve margin, in the event PSO has identified the potential for a locational imbalance, maintaining service integrity in the area, or other situations when reduction in load on the Company's system is warranted.

Total kW: Total kW is defined as the sum of the Firm kW and the Curtailable kW designated by the customer when contracting for service under this Rider and will be used to determine the applicable rate schedule.

Firm kW: Firm kW is defined as that portion of the Total kW that is not subject to curtailment under the terms and conditions of this Rider. The Firm kW will be designated by the Customer when contracting for service under this Rider. In addition, Firm kW may be adjusted annually by the Customer by written request to the Company.
Curtailable kW: Curtailable kW is defined as that portion of the Total kW subject to curtailment by the Company under this Rider. The Curtailable kW will be designated by the Customer when contracting for service. In addition, Curtailable kW may be adjusted annually by the Customer by written request to the Company.

CONDITIONS OF SERVICE

Customer may choose to have Total kW or some portion thereof designated as Curtailable kW. The amount of Total kW not designated as Firm kW shall constitute Customer's Curtailable kW. Customer's service must be equipped, at Customer's expense, with devices necessary to reduce Total kW during the period of curtailment to Firm kW or below and with metering devices necessary to verify that Total kW is at or below the Firm kW. In addition, the Company may request that the Customer's service be equipped, at Customer's expense, with communication equipment necessary to provide instantaneous load information to Company's designated system operating center.

Company will request curtailment of electric service under this Rider as the Company deems necessary for any reason including, but not limited to, maintaining service to firm loads, avoiding establishment of a new system peak, avoiding establishment of a peak demand in excess of 95% of the Company's forecasted peak load for the year, maintaining service integrity in the area, or other situations when reduction in load on the Company's system is warranted. To the extent possible, curtailable loads served under this Rider will be curtailed before any curtailment of firm loads is requested or required.

Requests for curtailment will be made by Company's System Operator via telephonic communication to Customer's designated representative(s). Upon application for service under this Rider, Customer shall designate the representative(s) and provide the telephone number at which they may be reached 24 hours a day. In the event of a curtailment for non-emergency purposes, Company will endeavor to provide notice to Customer at least 30 minutes prior to curtailment. In the event of a curtailment for emergency conditions, Company will attempt to provide as much prior notice as possible but is in no way obligated to give more than 15 minutes notice prior to curtailment. The Company may request the customer to install at Customer's expense electronic equipment necessary for automatic notification of curtailment.

No responsibility or liability of any kind shall attach to or be incurred by the Company or the AEP System for, or on account of, any loss, cost, expense or damage caused by or resulting from, either directly or indirectly, any curtailment of service under the provisions of this Rider.

The customer shall not receive credit for any curtailment periods in which the customer's curtailable energy is already down for an extended period due to a planned or unplanned outage as a result of vacation, renovation, repair, refurbishment, force majeure, strike, or any event other than the customer's normal operating conditions.

NON-COMPLIANCE PROVISIONS

There are no penalties for non-compliance under this Rider.

LIMITATIONS ON CURTAILMENTS

Curtailments under this Rider are limited as follows:

Daily Limit: No longer than 12 hours in any day, measured from midnight to midnight, except during system emergencies as described below.

Duration: The duration of an EMC event shall not be less than four hours.

Curtailment time is measured from the time the Company notifies the Customer via telephonic communication when the period of curtailment will begin to the time that Company notifies Customer via telephonic communication that the period of curtailment will end.

TERM OF CONTRACT

This Rider is being offered as an experimental service and may be withdrawn by the Company following written notice to each Customer served under the Rider given at least one year prior to such withdrawal. The obligation of the Customer shall continue for a minimum initial term of one year and continuing thereafter unless canceled by Customer following written notice given at least one year prior to such cancellation.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 80 - 1A
REPLACES SHEET NO. 80 - 1
EFFECTIVE DATE 12/31/13

SCHEDULE: SYSTEM RELIABILITY RIDER (SRR Rider)

AVAILABILITY

This Rider is in effect on a permanent basis and shall continue in effect until modified or terminated by order of the Oklahoma Corporation Commission.

This Rider is applicable to and becomes part of each OCC jurisdictional rate schedule. This Rider is applicable to energy consumption of retail customers served at secondary and primary service levels and to facilities, premises and loads of such retail customers.

For service billed under applicable rate schedules for which there is not metering, the monthly kilowatt-hour (kWh) usage shall be estimated by the Company and the SRR Factor shall be applied to the estimated kWh usage.

The SRR shall be calculated by multiplying the total billing kWh for each customer by the SRR Factor for that customer's class for the current month.

The SRR Factor shall be determined on a quarterly basis for each major rate class to incorporate the previous quarter's Eligible System Reliability Costs expended and adjusted by any over or under recovery of costs from a previous three month billing period and applied to the billings for the next quarter. The filings will occur on or before the 20th of the month in the months of March, June, September and December requesting to become effective with the first billing cycle of June, September, December and March, respectively. Eligible Distribution Reliability Costs are the incremental costs above those included in base rates from the last rate proceeding (Actual Distribution System Reliability Costs Expended less Distribution System Reliability Costs currently included in base rates). The eligible Distribution System Reliability Expenses are limited to $23.685 million per year. The eligible Distribution System Reliability Capital Costs are limited to a carrying charge recovery of $7.7 million annually. The SRR Factor will be calculated in accordance with the following methodology and will be applied to each kWh sold.

Method of Calculation For System Reliability Factor

An SRR Factor is calculated quarterly for each major rate class. The formula for the SRR Factor is as follows:

SRR Factor ($ per kWh) = [Distribution System Reliability Expenses (DRE) +Distribution System Reliability Capital Carrying Costs (DRC)] / Forecasted kWh Sales by Major Rate Class.

Method of Calculation For Eligible Distribution System Reliability Expenses

The Eligible Distribution System Reliability Expenses include the maintenance expense for vegetation management, system hardening and resiliency activities in excess of the costs currently included in base rates. The amount is limited to $23.685 million per year and is calculated as follows.

DRE = (DE+ DTU) * DAFE, where:

DE = Distribution System Reliability Expenses for the preceding quarter ($). Those distribution expenses recorded in FERC Account No. 593, Maintenance of Overhead Lines – Distribution in excess of the costs currently included in base rates. Successor accounts and sub accounts may be included as appropriate following advance notification to the Oklahoma Corporation Commission, Director of Public Utilities Division.

DTU = Distribution True-up amount to correct for any variance between actual distribution system reliability costs approved for SRR recovery and the actual revenue received from the DRE component of the SRR. The calculation will be done quarterly, which will determine the DTU for the following quarter. The calculation will be performed as follows:

DTU = DAR – ADER, where:

DAR = Actual revenue received from the application of the DRE component of the SRR Factor.

ADER = Actual DER which the Company intended to recover for the same period.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 80 - 3A
REPLACES SHEET NO. 80 - 3
EFFECTIVE DATE 12/31/13

SCHEDULE: SYSTEM RELIABILITY RIDER (SRR Rider)

DAFE = Distribution Allocation Factor for each major rate class from the Company's cost allocation study provided in the most recent rate case. The allocators from Commission Order No. 581748 in PUD Cause No. 201000050 are as follows:

Major Rate Class	Distribution Overhead Allocator A/C 593
Residential - Secondary	59.76943%*
SL4 & SL5 - Secondary	33.86518%*
SL3 - Primary	6.36539%
SL2 – Transmission Substation	0.00%
SL1 - Transmission	0.00%

* Lighting is included in the Secondary Rate Classes

Method of Calculation For Eligible Distribution System Reliability Capital Carrying Costs

The Eligible Distribution System Reliability Capital Carrying Costs includes the carrying charge on the capital costs of undergrounding, system hardening and resiliency activities not currently in rate base. The amount is limited to $7.7 million per year carrying charge and is calculated as follows.

DRC = (DC + DCTU) * DAFI, where:

DC= Distribution System Reliability Capital Carrying Costs for the preceding quarter ($). The eligible system reliability capital carrying costs are calculated as follows:

DC = DSRCI * CCR, where:

DSRCI= Actual cumulative distribution investment capitalized as a result of undergrounding, system hardening, or resiliency activities.

CCR = Company's Carrying Charge Rate.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
Januar 7, 2014	620006	PUD 201300202
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

APPROVED
JAN 7 2014
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 80 - 4A
REPLACES SHEET NO. 80 - 4
EFFECTIVE DATE 12/31/13

SCHEDULE: SYSTEM RELIABILITY RIDER (SRR Rider)

DCTU = Distribution Capital True-up amount to correct for any variance between actual distribution system reliability capital carrying costs approved for SRR recovery and the actual revenue received from the DC component of the SRR. The calculation will be done quarterly, which will determine the DCTU for the following quarter. The calculation will be performed as follows:

DCTU = DCAR – ADAR, where:

DCAR = Actual revenue received from the application of the DC component of the SRR Factor.

ADAR = Actual DCAR which the Company intended to recover for the same period.

DAFI = Distribution Allocation Factor for each major rate class from the Company's cost allocation study provided in the most recent rate case. The allocators from Commission Order No. 581748 in PUD Cause No. 201000050 are as follows:

Major Rate Class	Distribution System Reliability Capital Allocator A/C 594
Residential - Secondary	61.89539%*
SL4 & SL5 - Secondary	33.64625%*
SL3 - Primary	4.45836%
SL2 – Transmission Substation	0.00%
SL1 - Transmission	0.00%

* Lighting is included in the Secondary Rate Classes

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
Januar 7, 2014	620006	PUD 201300202
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

APPROVED
JAN 7 2014
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA	**SHEET NO. 80 - 5A**
P.O. BOX 201	**REPLACES SHEET NO. 80 - 5**
TULSA, OKLAHOMA 74102-0201	**EFFECTIVE DATE 12/31/13**
PHONE: 1-888-216-3523	
KIND OF SERVICE: ELECTRIC	

SCHEDULE: SYSTEM RELIABILITY RIDER (SRR Rider)

The Company will file with the Commission the requested SRR Quarterly Factor approximately 70 days preceding the requested effective date. The Director of the Public Utility Division will approve the requested SRR Factor to become effective with the first billing cycle of the requested billing month. The SRR Factor will remain in effect for three months and will expire unless a request for updated SRR Factor is filed by the Company.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
Januar 7, 2014	620006	PUD 201300202
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

APPROVED
JAN 7 2014
DIRECTOR OF PUBLIC UTILITY

Supplemental Page

System Reliability Rider Factors (SRR Rider)
(Previously Reliability Vegetation/Undergrounding Rider Factors)

	Residential & Residential - Secondary Lighting	S/L 4&5 and S/L 4&5 Secondary Lighting	S/L 3
Mar 06 – May 06	$0.001221	$0.001211	$0.000355
June 06 – Aug 06	$0.001568	$0.001973	$0.000819
Sept 06 – Nov 06	$0.001430	$0.001284	$0.000733
Dec 06 – Feb 07	$0.001019	$0.000950	$0.000784
Mar 07 – May 07	$0.002825	$0.002771	$0.000801
June 07 – Aug 07	$0.001675	$0.002191	$0.000754
Sept 07 – Oct 07	$0.002292	$0.002154	$0.000898
Nov 07 – Nov 07	$0.002245	$0.000418	$0.001355
Dec 07 – Feb 08	$0.002328	$0.001969	$0.001170
Mar 08 – May 08	$0.002161	$0.002984	$0.000574
June 08 – Aug 08	$0.001495	$0.001799	$0.000335
Sept 08 – Nov 08	$0.002303	$0.001584	$0.000753
Dec 08 – Jan 09	$0.002418	$0.002057	$0.000690
Feb 09	$0.002049	$0.001492	$0.000685
Mar 09 – May 09	$0.004489	$0.003079	$0.001178
June 09 – Aug 09	$0.001368	$0.001363	$0.000573
Sept 09 – Nov 09	$0.001869	$0.001432	$0.000676
Dec 09 – Feb 10	$0.002487	$0.002135	$0.000890
Mar 10 – May 10	$0.003300	$0.002140	$0.000916
June 10 – Aug 10	$0.001206	$0.001290	$0.000667
Sept 10 – Nov 10	$0.002034	$0.001580	$0.000544
Dec 10 – Jan 11	$0.001741	$0.001700	$0.000717
Feb 11	$0.001589	$0.001518	$0.000675
Mar 11 – May 11	$0.001309	$0.001017	$0.000466
Jun 11 – Aug 11	$0.001457	$0.001046	$0.000571
Sept 11 – Nov 11	$0.001839	$0.001135	$0.000624
Dec 11 – Feb12	$0.001609	$0.001253	$0.000673
Mar 12 – May 12	$0.001982	$0.001041	$0.000439
Jun 12 – Aug 12	$0.001025	$0.000742	$0.000383
Sept 12 – Nov 12	$0.001115	$0.000704	$0.000329
Dec 12 – Feb 13	$0.001954	$0.001253	$0.000619
Mar 13 – May 13	$0.002254	$0.001421	$0.000710
Jun 13 – Aug 13	$0.001225	$0.000814	$0.000406
Sept 13 – Nov 13	$0.001861	$0.001075	$0.000485
Dec 13 – Feb 14	$0.001740	$0.001204	$0.000577
Mar 14 – May 14	$0.002057	$0.001270	$0.000623
June 14 – Aug 14	$0.001001	$0.000610	$0.000306
Sept 14 – Nov 14	$0.002882	$0.001906	$0.000910
Dec 14 – Feb 15	$0.002563	$0.001694	$0.000804

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SCHEDULE: SOUTHWEST POWER POOL TRANSMISSION COST (SPPTC) TARIFF

AVAILABILITY

This Tariff is applicable to and becomes part of each OCC jurisdictional rate schedule and will apply to energy consumption of retail customers served at all service levels and to facilities, premises and loads of retail customer.

The SPPTC will be implemented the first billing cycle of the month following Commission approval of the SPPTC and shall remain in effect until closed by Commission order. The SPPTC will be reviewed for the purposes of extension, modification or termination during the next PSO base rate case, which will be filed no later than 26 months following the implementation of the SPPTC.

This Tariff will include projected Southwest Power Pool (SPP) Base Plan expenses (Schedule 11 of the SPP Open Access Transmission Tariff) incremental to such costs included in PSO's most recent base rate case, PUD Cause No. 201000050, including any credits or refunds. Base plan costs are associated with projects constructed by non-PSO transmission owners within the SPP, excluding costs of projects constructed by Oklahoma Transmission Company, Inc. (OK Transco).

The SPPTC shall be calculated on the customer's bill by multiplying the total billing kilowatt-hours (kWh) for each customer by the SPPTC Factor for that customer's class for the current month. For service billed under applicable rate schedules for which there is not metering, the monthly kWh usage shall be estimated by the Company and the SPPTC Factor shall be applied to the estimated kWh usage.

The SPPTC Factors shall be determined on an annual basis for each major rate class. The factors shall include the upcoming period's incremental projected SPP Base Plan expenses plus an over or under recovery of actual expenses compared to revenues received under the Tariff for the prior period. The initial SPPTC Factors and the projected SPP Base Plan Expenses to be recovered pursuant to such Factors are attached as Schedule 1 to this Tariff.

Method of Calculation for SPPTC Factor:

An SPPTC Factor is calculated annually for each major rate class on a per kWh basis. The formula for the SPPTC Factor is as follows:

$$\textbf{SPPTC Factor} = \frac{\textbf{(SPP Expenses * Class Transmission Allocator) + True-up}}{\textbf{kWh by Major Rate Class}}$$

where,

APPROVED

DEC 16 2011

DIRECTOR OF
PUBLIC UTILITIES

SPP Expenses = Projected Schedule 11 Base Plan Expense of the SPP Open Access Tariff associated with projects constructed by non-PSO or AEP affiliated transmission owners within SPP, excluding costs of projects constructed by AEP affiliates other than SWEPCO or, if applicable, Southwest Transmission Company, incremental to such costs included in PSO's most recent base rate case, PUD Cause 201000050, including any credits and refunds allocated to the Oklahoma retail jurisdiction using the most recently approved jurisdictional transmission allocator.

Class Transmission Allocator = the most recently approved class transmission allocator for each major rate class within the Oklahoma retail jurisdiction.

True-up = Over or under recovery of the previous period's actual SPP Expenses compared to SPPTC revenues by major rate class.

kWh by Major Rate Class = Projected kWh sales for each major rate class for the twelve month effective period of the SPPTC Factors.

Annual Re-determination:

Beginning in September of 2012, and continuing each year thereafter, the Company will file the re-determined SPPTC factors in this Cause (PUD 201100106) for implementation on the first billing cycle of the following October. Calculations for the re-determined rates shall be made by the application of the SPPTC formula set forth in this tariff. The Company shall file information sufficient to document and support the reasonableness of the projected SPP Expenses, the True-up amounts during the previous period, and the re-determined SPPTC rates with each annual re-determination.

Following the filing of the re-determined SPPTC factors, the Commission Staff will convene a technical conference where the company shall provide the projected revenue impact of the annual SPP Expense re-determination for each major customer class. The company shall also provide any information or studies regarding the economic benefit or analysis to customers associated with the eligible incremented SPP expenses.

The company will address the reasonableness of SPP Expenses collected through the SPPTC during the next PSO base rate case and in future base rate cases. Based on the review by the Commission Staff and parties in the next base rate case, any over or under recovery of SPP Expenses collected through the SPPTC shall be refunded to or collected from customers with interest calculated at the applicable Commission established interest rate applied to customer deposits for deposits held one year or less, or the interest rate applied to customer deposits held for more than one year.

Should a cumulative over-recovery or under-recovery balance arise during any SPPTC cycle which exceeds ten percent (10%) of the annual SPP Expenses reflected in the current SPPTC, then either the Commission Staff or the Company may propose an interim revision to the currently effective SPPTC rate.

Supplemental Page

Southwest Power Pool Transmission Cost Factors SPPTC

Effective Date	Residential Secondary	Commercial SL 4&5	Industrial SL 3	Industrial SL 2	Industrial SL 1
12/20/2011	$0.000754	$0.000572	$0.000439	$0.000358	$0.000327
11/28/2012	$0.001329	$0.000985	$0.000757	$0.000590	$0.000559
09/27/2013	$0.002230	$0.001659	$0.001291	$0.000970	$0.000911
09/29/2014	$0.002554	$0.001918	$0.001505	$0.001080	$0.001040

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 85 - 1B
REPLACES SHEET NO. 85 - 1A
EFFECTIVE DATE: 04/01/13

SCHEDULE: DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DSM RIDER)

AVAILABILITY

DSM Rider is designed to recover costs associated with the Energy Efficiency and Demand-side Management programs (DSM Programs) as authorized in PUD 200900196, Order 572836.

This Rider is applicable to and becomes part of each OCC jurisdictional rate schedule. This Rider is applicable to energy consumption of retail customers and to facilities, premises and loads of such retail customers.

The DSM Factor shall be determined annually for each major rate class using the DSM Program projected costs for that year and any true-up amounts included from the previous year. The DSM Factor will be calculated in accordance with the following methodology and will be applied to each kWh sold.

METHOD OF CALCULATION FOR DSM RIDER

The DSM Factor is calculated annually for each major rate class. The formula for the DSM Factor is as follows:

DSM Factor = {[(Projected Program cost + DSM true-up for previous period) * Demand or Energy Allocator)]} / Class Annual kWhs.

Method of Calculation For DSM Rider:

PDSM = {[(PPCDR + TDSMDR) * DF]} + {[(PPCEE + TDSMEE) * DEF] + OPT OUT}, where:

PPCDR = Budgeted Demand Response Program Cost for the year associated with the DSM programs approved by the OCC.

PPCEE = Budgeted Energy Efficiency Program Cost for the year associated with the DSM programs approved by the OCC.

TDSMDR = Demand Response program true-up balance from the previous period where: TDSMDR = (APCDR – PPCDR) + (ALRDR – PLRDR) + (ASHDR – PSSDR) + (ADSMDR Revenues – PDSMDR)

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
November 15, 2012	604214	PUD 201200128
January 31, 2011	581748	PUD 201000050
March 3, 2010	572836	PUD 200900196
January 29, 2009	564437	PUD 200800144
August 1, 2008	555302	PUD 200700449

APPROVED
MAR 22 2013
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 85 - 2B
REPLACES SHEET NO. 85 - 2A
EFFECTIVE DATE: 04/01/13

SCHEDULE: DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DSM RIDER)

APCDR = (Actual Program costs)

ALRDR = (Actual Calculated Lost revenues) where:

ALRDR = Actual Lost Revenues as calculated by Demand Response program. The ALRDR is calculated as follows:

ALRDR = (ECR * CKWHDR)

ECR = Embedded cost per kWh by class; Embedded Cost per kWh is calculated by dividing the final revenue allocation by class, established in the most recent rate proceeding, by the total kWhs also established for use in that proceeding.

The ECR by classes for use in this tariff will be:

Participating Class	COS $/kWh
Residential	$ 0.028908
Small Commercial	$ 0.030609
Large Commercial & Industrial	$ 0.028221
Large Industrial	$ 0.013474

CKWHDR = Cumulative kWhs for saved for Demand Response programs.

The kWh savings used in the Lost Revenue calculation will accumulate until the final order in a new base rate case, at which time the cumulative kWhs will be zeroed out until the next calculation of the DSM Rider and new DSM programs are implemented.

ASHDR = (Actual Calculated Shared Savings)

ASHDR = Actual shared saving as calculated, by customer classes, resulting from the implementation of the Demand Response Programs.
The ASHDR is calculated as follows:

ASHDR = Shared Benefit + Program Incentives where:

Shared Benefit = Net benefit * Sharing Percentage (SP) where:

Net Benefit = is a product of the Program Administrator Cost Test (PACT), also referred to as the Utility Cost Test (UCT), for the Demand Response Programs with measurable benefits.

PACT = Avoided capacity and energy costs – Equipment + Demand Response program Administration costs.

SP = 15% where:

Program Incentives = Program costs * sharing percentage (SP2)

Program costs = budgeted program costs for DSM period

SP2 = 15%

ADSMDR = (Total revenues collected from DSM Rider)

PDSMDR = (DSM Revenues projected to be recovered during previous period)

TDSMEE = Energy Efficiency program true-up balance from the previous period where:
TDSMEE = (APCEE – PPCEE) + (ALREE – PLREE) + (ASHEE – PSSEE) + (ADSMEE Revenues – PDSMEE)

APCEE = (Actual Program costs)

ALREE = (Actual Calculated Lost revenues)

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 85 - 4B
REPLACES SHEET NO. 85 - 4A
EFFECTIVE DATE: 04/01/13

SCHEDULE: DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DSM RIDER)

ALREE = Actual Lost Revenues as calculated by Energy Efficiency program. The ALREE is calculated as follows:

ALREE = (ECR * CKWHEE)

CKWHEE = Cumulative kW'hs saved for Energy Efficiency programs.

The kWh savings used in the Lost Revenue calculation will accumulate until the final order in a new base rate case, at which time the cumulative kWhs will be zeroed out until the next calculation of the DSM Rider and new DSM programs are implemented.

ASHEE = (Actual Calculated Shared Savings)

ASHEE = Actual shared saving as calculated, by customer classes, resulting from the implementation of the Energy Efficiency Programs.

The ASHEE is calculated as follows:

ASHEE = Shared Benefit + Program Incentives where:

Shared Benefit = Net benefit * Sharing Percentage (SP) where:

Net Benefit = is a product of the Program Administrator Cost Test (PACT), also referred to as the Utility Cost Test (UCT), for the Energy Efficiency Programs with measurable benefits.

PACT = Avoided capacity and energy costs – Equipment + Energy Efficiency program Administration costs.

SP = 15% where:

Program Incentives = Program costs * sharing percentage (SP2)

Program costs = budgeted program costs for DSM period

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
November 15, 2012	604214	PUD 201200128
January 31, 2011	581748	PUD 201000050
March 3, 2010	572836	PUD 200900196
January 29, 2009	564437	PUD 200800144
August 1, 2008	555302	PUD 200700449

APPROVED
MAR 22 2013
DIRECTOR OF PUBLIC UTILITY

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 85 - 5B
REPLACES SHEET NO. 85 - 5A
EFFECTIVE DATE: 04/01/13

SCHEDULE: DEMAND SIDE MANAGEMENT COST RECOVERY RIDER (DSM RIDER)

SP2 = 15%

ADSMEE = (Total revenues collected from DSM Rider)

PDSMEE = (DSM Revenues projected to be recovered during previous period)

DF = Demand Allocation Factor for each major rate class (based upon allocators from Cause PUD 201000050) are as follows:

DF Allocator	Major Rate Class
48.69%	Residential - Secondary
32.14%	Commercial - Secondary
8.77%	SL3 – Primary
8.68%	SL2 – Primary Sub
1.72%	SL1 – Transmission

* Lighting included in the Commercial Secondary Rate Class

DEF = Demand/Energy Allocation Factor for each major rate class (based upon allocators from Cause PUD 201000050) are as follows:

DEF Allocator	Major Rate Class
42.72%	Residential - Secondary
32.13%	Commercial - Secondary
10.51%	SL3 – Primary
12.06%	SL2 – Primary Sub
2.57%	SL1 – Transmission

* Lighting included in the Commercial Secondary Rate Class

OPTIONAL PARTICIPATION ADJUSTMENT (OPT OUT):

The opt-out period for high-volume electricity users (a single customer using more than fifteen million kWh of electricity per year, regardless of the number of meters or service locations) will be for one month each year, beginning on December 1 and closing on December 31. Any high-volume electricity user may opt out of either all energy efficiency or all demand response programs, or both; and

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
November 15, 2012	604214	PUD 201200128
January 31, 2011	581748	PUD 201000050
March 3, 2010	572836	PUD 200900196
January 29, 2009	564437	PUD 200800144
August 1, 2008	555302	PUD 200700449

APPROVED
MAR 22 2013
DIRECTOR OF PUBLIC UTILITY

they may opt out for the program year or for the entire program period. They must submit notice of such decision to the Director of the Public Utility Division and to PSO on or before December 31 of each year. After December 31, high-volume electricity users may no longer opt out or opt in until the next enrollment period.

Supplemental Page

PUBLIC SERVICE COMPANY OF OKLAHOMA
Demand Side Management Cost Recovery Rider (DSM Rider)
Consumer Programs 2014

2014 PSO DSM Factors

Energy Programs

MAJOR RATE CLASS	**DPCR Factor**
Residential - Secondary	0.002324
Commercial/Industrial	0.003486

Demand Programs

MAJOR RATE CLASS	**DPCR Factor**
Residential - Secondary	0.000268
Commercial/Industrial	0.000310

Total Programs

MAJOR RATE CLASS	**DPCR Factor**
Residential - Secondary	0.002592
Commercial/Industrial	0.003796

The above factors will be applied to kWh sales on bills rendered beginning with the April 2014 Cycle 1 billing.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 87
EFFECTIVE DATE 1/31/11

SCHEDULE: PURCHASED POWER CAPACITY (PPC) RIDER

AVAILABILITY

This Rider is applicable to and becomes a part of each OCC jurisdictional rate schedule in which reference is made to Purchased Power Capacity Adjustment.

ADJUSTMENT

The Purchased Power Capacity Adjustment shall be calculated by multiplying the total billing kilowatt-hours (kWh) by the Service Level Purchased Power Capacity Adjustment Factor for the current billing period. The Service Level Purchased Power Capacity Adjustment Factor shall be determined on an annual basis in the following manner:

PPCA = (PPC$ / S) + DEF$

WHERE:

PPCA = The Service Level Purchased Power Capacity Adjustment Factor (expressed in dollars per kWh) to be applied per kWh consumed.

PPC$ = SYS$ x SLPDA

S = Retail service level kWh sales for the period.

DEF$ = The service level prior year's balance sheet amount for the Unrecovered Purchased Power Capacity Cost divided by the service level annual retail kWh sales.

WHERE:

SYS$ = The annual Purchased Power Capacity costs applicable to native load customers set forth in the FERC Account 5550.

SLPDA = The service level production demand allocator from the most recent rate case test year cost of service study.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

Supplemental Page

Purchased Power Capacity Rider (PPCR)

Public Service Company of Oklahoma

Purchased Power Capacity Rider ($/kWh)

Period	S/L 6	S/L 4/5	S/L 3	S/L 2	S/L 1
Feb 09 – Jan 10	0.000987	0.000987	0.000579	0.000447	0.000422
Feb 10 – Jan 11	0.001030	0.001030	0.000639	0.000387	0.000527
Feb 11 - Jan 12	0.000307	0.000307	0.000242	0.000176	0.000086
Feb 12 - Jan 13	0.000044	0.000044	(0.000002)	(0.000014)	0.000061
Feb 13 – Jan 14	0.000104	0.000104	0.000087	0.000063	0.000008
Feb 14 – Jan 15	0.000159	0.000159	0.000081	0.000053	0.000089

AVAILABILITY

Rider BLPP is designed to recover all costs associated with the Exelon contract along with recovery of the one-time RFP costs. This rider will be effective beginning the first billing cycle following the approval of the BLPP Rider to recover the one-time RFP Costs. The rider will be effective for the remainder of the costs beginning with the first billing cycle following the receipt of power.

This Rider is applicable to and becomes a part of each OCC jurisdictional rate schedule. This Rider is applicable to energy consumption of retail customers and to facilities, premises and loads of such retail customers.

The BLPP Factor shall be determined on an annual basis for each major rate class to incorporate the annual forecasted costs for the subsequent year and any true-up amounts included from the previous annual billing period. The BLPP Factor will be calculated in accordance with the following methodology and will be applied to each kWh sold.

Method of Calculation For BLPP Factor (BLPPF):

The BLPP Factor is calculated annually for each major rate class using the following formula:

BLPP Factor ($ per kWh) = [BLPPTC] / Forecasted kWh Sales by Major Rate Class.

BLPPTC = Total Annual Costs of Long-Term Base Load Purchased Power

BLPPTU = True-Up Amount to Correct for Variance Between Projected and Actual

BLPPAR = Actual Revenue Received from the Rider for the Reconciliation Period

AEBLPP = Amount Projected to be Recovered for the Reconciliation Period

---

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 88 - 2
EFFECTIVE DATE 1/31/11

SCHEDULE: LONG-TERM BASE LOAD PURCHASED POWER (BLPP) RIDER

BLPPTC = [((CAP + OTC + BLPPTU) * PAF) + ((IP + SU + EN) * EAF)], where:

IP = Annual Imbalance Payments per contract terms
SU = Annual Start Up Costs per contract terms
CAP = Annual Capacity Costs per contract terms
EN = Annual Energy Costs per contract terms
OTC = One Time Costs, Independent Monitor Fees and SPP Transmission Impact Assessment Fees

BLPPTU = BLPP True-up amount to correct for any variance between the BLPP costs approved for BLPP rider recovery and the actual revenue received from the BLPPTC component of the BLPP rider. The calculation will be done annually, which will determine the BLPPTU for the following year. The calculation will be performed as follows:

BLPPTU = BLPPAR – AEBLPP, where:

BLPPAR = Actual revenue received from the application of the BLPPF

AEBLPP = BLPPTC which the Company intended to recover for the same period

PAF = Production Allocation Factor for each major rate class (based upon allocators from Cause PUD 201000050) are as follows:

Production Allocator	Major Rate Class
48.8200%	Residential - Secondary
32.0069%	Commercial - Secondary
8.7677%	SL3 – Primary
8.6845%	SL2 – Primary Sub
1.7209%	SL1 – Transmission

* Lighting included in the Secondary Rate Classes

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
November 25, 2009	570156	PUD 200900099

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SHEET NO. 88 - 3
EFFECTIVE DATE 1/31/11

KIND OF SERVICE: ELECTRIC

SCHEDULE: LONG-TERM BASE LOAD PURCHASED POWER (BLPP) RIDER

EAF = Energy Allocation Factor for each major rate class (based upon allocators from Cause PUD 201000050) are as follows:

Energy Allocator	Major Rate Class
36.8621%	Residential - Secondary
32.0106%	Commercial - Secondary
12.2591%	SL3 – Primary
15.4392%	SL2 – Primary Sub
3.4290%	SL1 – Transmission

* Lighting included in the Secondary Rate Classes

After approval by the Director of the Public Utility Division the requested BLPP Factor will become effective with the first billing cycle of the requested billing month.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
November 25, 2009	570156	PUD 200900099

Supplemental Page
Base Load Purchased Power (BLPP) Factors

	Residential & Residential Sec Lighting	S/L 4 & 5 S/L 4 & 5 Sec Lighting	Primary 3	S/L 2	S/L 1
June 12 – Feb 13	$0.008119	$0.007511	$0.007170	$0.005703	$0.006446
Mar 13 – Oct 13	$0.006266	$0.005475	$0.005015	$0.003971	$0.004348
Nov 13 – Oct 14	$0.008716	$0.007529	$0.006807	$0.005358	$0.005708
Nov 14– Oct 15	$0.007686	$0.006758	$0.006081	$0.004811	$0.004929

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 49-B
REPLACES SHEET NO. 49-1
EFFECTIVE DATE 1/31/11

SCHEDULE: REACTIVE POWER CHARGE

AVAILABILITY

This schedule is applicable to all customers having a Reactive Power Charge clause in the standard rate schedule.

REACTIVE POWER CHARGES:

The customer's monthly maximum Reactive Power (KVAR) requirement must be no more than 30% of the monthly maximum demand (kW) requirement. When the Company determines the KVAR requirement may exceed 30%, the Company may install suitable measuring equipment at the metering point to determine the customer's monthly maximum kVAR and monthly maximum kW requirements.

For customers whose monthly maximum kVAR requirements exceed 30% of the monthly maximum kW requirement, an additional charge will be assessed for each kVAR required above 30% of the monthly maximum kW requirement established by the customer.

REACTIVE POWER RATES EFFECTIVE THROUGH JUNE 2011

The current rates for each kVAR assessed above 30% of the monthly maximum kW requirement established by the customer will continue through June 2011. After June 2011, the new kVAR charges set out below will apply. The current kVAR charges are as follows:

Service Level 4 & 5	$0.31 per kVAR assessed above 30% of monthly maximum demand
Service Level 3	$0.31 per kVAR assessed above 30% of monthly maximum demand
Service Level 1 & 2	$0.33 per kVAR assessed above 30% of monthly maximum demand

REACTIVE POWER RATES EFFECTIVE FIRST BILLING CYCLE OF JULY 2011

PSO will enact a revised kVAR charge of $0.66 for each kVAR required above 30% of the monthly maximum kW requirement established by the customer beginning with the first billing cycle of July 2011, based on the Final Order in Cause No. PUD 201000050, at which time the current kVAR rates set out above will expire.

Service Level 4 & 5	$0.66 per kVAR assessed above 30% of monthly maximum demand
Service Level 3	$0.66 per kVAR assessed above 30% of monthly maximum demand
Service Level 1 & 2	$0.66 per kVAR assessed above 30% of monthly maximum demand

APPROVED
MAY 27 2011
DIRECTOR OF
PUBLIC UTILITIES

PUBLIC SERVICE COMPANY OF OKLAHOMA	**SHEET NO. 100 - 1**
P.O. BOX 201	**REPLACES SHEET NO. 90 - 1A**
TULSA, OKLAHOMA 74102-0201	**EFFECTIVE DATE 1/31/11**
PHONE: 1-888-216-3523	
KIND OF SERVICE: ELECTRIC	

SCHEDULE: SERVICE CHARGES (SC)

Service Connect Fee

The Connect Fee is charged to the customer for establishing each new electrical connection service to an account, including temporary service. After receipt of adequate notification, connects are performed during normal business hours and the appropriate routine Connect Fee is charged. If a customer requests that the connect be completed with less than adequate notice, and the Company fulfills that request, the appropriate after-hours Connect Fee may be charged. Requests for electrical connection where construction is required may require an additional charge for the necessary construction. A request for an after-hours connect may not be an option when construction is required, depending on the amount of construction needed to make the electrical connection.

When a meter is disconnected or turned off at the direction of the Customer, and the Customer for whom it was disconnected or turned off has it reconnected or turned back on at the same location within 12 billing periods of the time service was interrupted, a charge as follows shall be paid at the time the Customer requests the meter to be reconnected or service is turned back on: “An amount equal to the total minimum monthly billings from the date of interruption to the date of reinstatement, or the applicable reconnect charge, which ever is greater.”

Normal Hours	After Hours
$22.00	$56.00

Service Reconnection Fee

The Service Reconnection Fee is charged to the customer to reestablish electric service during normal working hours for any customer who has been disconnected for non payment. To reestablish electric service outside of normal working hours, the after-hours reconnection charge will be assessed.

	Normal Hours	After Hours
Self Contained Meter	$22.00	$56.00
Pole or Subsurface Box	$66.00	$171.00
CT Meter	$55.00	$168.00

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	**581748**	**PUD 201000050**
January 29, 2009	**564437**	**PUD 200800144**

Meter Tampering Fee

Any time there is unauthorized access into the meter enclosure and there is evidence of current diversion, meter tampering, or other deliberate act(s) contributing to theft of service, the Meter Tampering Fee will be based on the minimum cost to the company during the initial investigation if meter tampering is confirmed. Any additional labor costs needed to normalize the equipment or to investigate the tampering will be charged to the customer based on the established hourly rates listed.

In addition to the Meter Tampering Fee, charges will be assessed based on an estimate of the difference between meter readings during the estimated duration of the theft of service and what the meter should have actually metered. Also, charges for any cost of repairs of replacement of damaged facilities, missing or destroyed meter, installation of protective equipment, or relocation of meter will also be charged is such is required.

	Normal Hours	After Hours
Labor Cost per hour		
Revenue Protection Coordinator	$24.56	$36.83
Analysts	$40.65	$40.65
Service Tech	$41.03	$61.55
Meter Tech	$39.34	$59.02
Field Operations Specialists	$24.56	$36.83
Transportation Cost per hour (minimum 1 hr. charge plus mileage at current IRS rate		
½ ton 4WD truck	$4.65 Plus mileage at current IRS rate	
4WD service bucket	$22.65 Plus mileage at current IRS rate	
Supplies and miscellaneous expenses	At Cost	

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 100 - 3
REPLACES SHEET NO. 90 - 3A
EFFECTIVE DATE 1/31/11

SCHEDULE: SERVICE CHARGES (SC)

Broken Meter Seal Fee

Any time there is an unauthorized breakage of the meter seal, regardless if it is for unauthorized reconnection or service, unauthorized access into the meter enclosure, or for reasons not identifiable, the Broken Meter Seal Fee will be charged. Additional charges for any cost of repairs or replacement of damaged facilities, installing protective equipment, or relocation of meter will also be charged if such is required.

Broken Meter Seal Fee	$50.00
*Plus all cost to repair or replace facilities	

Meter Test Fee

The Meter Test Fee will be charged to the customer for each meter tested, at customer's request, other than tests conducted under the frequency guidelines specified in PSO's Rules and Regulations for meter tests at no cost to customer. If the results of a test indicate the meter accuracy to be outside the tolerance limits specified by the OCC, the Meter Test Fee will be waived.

	Meter Test Fee
Self-Contained Meter	$48.00
CT Meter	$81.00

Special Meter Reading Fee

The Special Meter Reading Fee will be charged when a Residential or Commercial customer requests more than once within a twelve month period that a meter be re-read to check the accuracy of the Company's routine meter reading, or requests a special reading be taken between normal meter reading cycles. Special meter readings will be performed only during regular business hours. The fee will not be charged for a re-read if the new reading indicates that the original reading was in error.

Special Meter Reading Fee	$20.00

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 100 - 4
REPLACES SHEET NO. 90 - 4A
EFFECTIVE DATE 1/31/11

SCHEDULE: SERVICE CHARGES (SC)

Special Meter Fee

The Special Meter Fee is for special metering and/or non-standard metering reports, requested by the customer, that are in addition to what is required for the Company to bill the customer for service. The requested product or service, if the Company agrees to provide them, must be appropriate for an electric utility to provide and not be prohibited under the OCC's service restrictions. This fee will be charged monthly to the customer and will be based on the estimated re-occurring monthly costs plus estimated monthly maintenance on any special equipment required for providing the requested service. This monthly fee will be charged in addition to any installation costs for the special metering equipment requested.

Any special equipment required for providing the requested service. This monthly fee will be charged in addition to any installation costs for the special metering equipment requested.

Special Meter Fee	$25.00

Radio Frequency Meter Installation Fee

The Radio Frequency Meter Installation Fee will be charged when a Residential or Commercial customer served under a rate schedule requests the Company to install a radio frequency meter at the customer's service address for meter reading purposes. The Company may also request that a customer have a radio frequency meter installed on the customer's premises as a mutually agreeable solution to a locked gate, animal concern, safety concern or other reason that has prevented Company personnel from accessing the Company's meter for meter reading purposes. All radio frequency meters installed remain the property of the Company.

	Single Phase	Three Phase
Exchange Existing Meter	$94.49	$281.49
New Meter Installation	$46.10*	$233.10*
Additional Meters at Same Premises	$74.94**	$268.29**
*For new installations, only materials to upgrade the standard meter are included		
**For additional meters on the same premises, only materials, task labor, and additional vehicle rates are included in the fee		
Travel time is recovered in the fee for the original meter on the same premise		

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 100 - 5
REPLACES SHEET NO. 90 - 5A
EFFECTIVE DATE 1/31/11

SCHEDULE: SERVICE CHARGES (SC)

Inaccessible Company Equipment Fee

The Inaccessible Company Equipment Fee may be charged to the customer each month that the Company is unable to gain access to Company's equipment located on the customer's property. The customer will be allowed one notification from the Company at no charge. For each instance the Company is unable to gain access to a meter, an estimated meter reading for that month will be billed to the customer for electrical connection service based upon the estimated reading. In addition to the service charges based upon the estimated reading, the customer may be billed the Inaccessible Company Equipment Fee.

Inaccessible Company Equipment Fee	$63.00

Late Payment Fee

The Late Payment Fee of 1.5% of the total unpaid balance for services and charges, excluding security deposit, will be added to the next monthly billing for bills not paid within twenty-one (21) days after the current bill is mailed.

Returned Check Fee

The Returned Check Fee is charged for each check returned unpaid by a financial institution to the Company.

Returned Check Fee	$22.00

SCHEDULE: LEAVE-ON AGREEMENT (LOA)

AVAILABILITY

The Company is authorized to enter into a written Leave-On Agreement with an owner of rental property, at the option of such property owner. If such Leave-On Agreement is entered into, the charges set forth therein for connection of service to rental units covered by the Agreement shall be those set forth below. The charges set forth herein and in such Agreement are exclusive of and in addition to charges for electric service rendered under any of the Company's rate schedules.

The term "Leave-On Agreement", as used herein, shall mean a written agreement between the Company and an owner of rental property, whereby said owner agrees to be responsible for payment of all charges for electric service provided to a rental unit covered by such agreement during any period subsequent to the closing of an account for service to a tenant or occupant of such rental unit and prior to the opening of an account for service to a new tenant or occupant of such rental unit.

SERVICE CHARGES

1. A charge of $35.00 per Leave-On Agreement, plus $0.50 for each rental unit covered by such Agreement, shall be assessed to the owner, such charge to be paid in full at the time such Agreement is entered into. An owner which has entered into an effective Leave-On Agreement prior to the effective date of this schedule shall not be assessed this initial charge, but shall be assessed the charges set forth below.

2. A Connection Charge of $11.00 shall be assessed to the owner each time it is necessary to establish an account in the owner's name for service provided to a rental unit in accordance with the terms of the Leave-On Agreement.

3. A Disconnect Charge of $7.00 shall be assessed to the owner each time service to a rental unit covered by a Leave-On Agreement is disconnected, rather than being transferred to the account of a new tenant or occupant of such rental unit.

PUBLIC SERVICE COMPANY OF OKLAHOMA	**SHEET NO. 102 - 1**
P.O. BOX 201	**REPLACES SHEET NO. 92 - 1**
TULSA, OKLAHOMA 74102-0201	**EFFECTIVE DATE 1/31/11**
PHONE: 1-888-216-3523	
KIND OF SERVICE: ELECTRIC	

SCHEDULE: DEPOSIT PLAN

AVAILABILITY

The following is Public Service Company of Oklahoma's Deposit Plan for all classification of Customers. Where a difference in the deposit criteria exists between Residential and non-Residential Customers, it shall be specifically stated in the plan.

PURPOSE OF SECURITY DEPOSIT

Customer deposits are security for the payment of any unpaid amounts the customer may owe at the time of service termination. This amount includes, but is not limited to:

- Monthly bills
- Service charges
- Meter diversion charges
- Temporary service

DEPOSIT RECORDS

Accurate records are maintained on customer deposits for two years after service termination or deposit is refunded or applied. These records shall include:

- Account number
- Customer's name
- Current address
- Deposit receipt number
- Date of deposit
- Amount of deposit
- Date interest paid to
- Amount of interest paid to date
- Date deposit refunded or applied

ESTABLISHING DEPOSIT AMOUNT

Public Service Company shall not require a deposit of more than 1/6 of the average annual bill based on previous billing history on the account. No deposit will be required from a residential customer who has received the same or similar type and classification of service for twelve (12) consecutive months and service was not terminated for non-payment nor was payment late more than twice nor was a check for payment dishonored. The twelve (12) month service period shall have been within eighteen (18) months prior to the application for new service.

If the billing history is insufficient or not available, PSO may estimate the average based on one or more of the following:

1. Square footage
2. Appliance usage
3. Conservation measures
4. Same type of service at another location
5. Load (which includes connected horsepower, lighting, incidental load and hours of operation)
6. Type of heating and cooling
7. Minimum deposit amount

Deposit amounts may be reduced when one or more of the following conditions exist:

1. Reduction in installed appliances or equipment
2. Reduced usage
3. Installation of higher efficiency heating/cooling equipment
4. Added conservation measures
5. Rate changes
6. Sufficient on-peak and off-peak billing history

ISSUING DEPOSIT RECEIPTS

Customers paying deposits at an authorized PSO paystation will be given a non-assignable receipt for their deposit at that time. Receipts for billed deposits shall be mailed to the customer within 10 days after the billed deposit amount is paid.

PUBLIC SERVICE COMPANY OF OKLAHOMA	**SHEET NO. 102 - 3**
P.O. BOX 201	**REPLACES SHEET NO. 92 - 3**
TULSA, OKLAHOMA 74102-0201	**EFFECTIVE DATE 1/31/11**
PHONE: 1-888-216-3523	
KIND OF SERVICE: ELECTRIC	
SCHEDULE: DEPOSIT PLAN	

INTEREST ON ACTIVE DEPOSITS

Accrued interest on active deposits held at least 30 days or longer, shall be credited to the customer's billing at least once annually. If deposit was refunded or applied within one year, interest will be based on one year U.S. Treasury Securities interest rate, otherwise if deposit retained, interest will be based on ten year U. S. Treasury Securities interest rate. These rates will be established by the Oklahoma Corporation Commission (OCC).

REFUNDING DEPOSIT AND INTEREST ON FINAL BILLS

Deposit and accrued interest shall be applied to the final billing up to and including the service termination date. When the deposit and interest exceed the final billing, the credit balance shall be refunded by refund draft within 30 days.

The customer shall not be required to return the deposit receipt at the time of service termination or time of refund.

DISPUTED BILLS

PSO may withhold refund or return of a customer's deposit until a dispute of any charges covered by the deposit is resolved.

RESIDENTIAL ACCOUNTS WITH INADEQUATE DEPOSITS

PSO shall communicate with the customer, by letter, to obtain a cash deposit or one of the appropriate deposit options on accounts with inadequate deposit amounts which have become past due two or more times in the last 12 months, has had service discontinued for non-payment, or had a check for payment dishonored more than once in a year.

TRANSFER/SALES

With the sale or transfer of service territory to any other utility, PSO shall file with the application of transfer, a verified listing of all active customer deposit records affected by this sale or transfer.

OPTIONS TO CASH DEPOSITS FOR RESIDENTIAL CUSTOMERS

Based on information provided by the customer, PSO shall consider one of the following options to a cash deposit that will satisfy both the customer and company needs:

- **LETTER OF GUARANTEE**

  PSO customers with 12 months good pay history may sign a *Residential Letter of Guarantee* for any residential customer. The Guarantor will be liable for the terms specified in the *Residential Letter of Guarantee*. The form, which includes *Third Party Notification,* is available, upon request from PSO.

- **LETTER OF REFERENCE**

  A letter of referral from another utility company that indicates satisfactory payment record.

- **DEFERRED DEPOSIT AMOUNT**

  The deposit amount is recorded on the customer's account, but is not charged unless the customer has a past due bill (greater than $10.00) and the account becomes past due at any monthly bill date.

- **BILLED DEPOSITS**

  Rather than pay the deposit amount when applying for electric service, the customer may pay the billed deposit with their first electric service bill.

- **INSTALLMENTS ON BILLED DEPOSIT**

  It is possible to arrange to make the billed deposit payments in installments, with partial payment allowed initially and installments not to exceed three consecutive months.

- **PREVIOUS PAY HISTORY**

A deferred deposit may be required of a residential customer whose last 12 consecutive months of service was with satisfactory pay history, provided service was terminated within the last 18 months.

REFUNDING DEPOSITS ON ACTIVE RESIDENTIAL ACCOUNTS

Customers' payment history shall be reviewed monthly. Customers with 10 out of 12 months satisfactory pay history (as defined in the next section) will be refunded their deposit with accrued interest by either a credit against billing or by refund draft.

SATISFACTORY PAYMENT HISTORY -- RESIDENTIAL

PSO considers a satisfactory pay customer as a customer who meets all of the following criteria:

- No past due or returned check balance in current month
- No more than two 30-day balances in last 12 months
- No more than one returned check in the last 12 months
- No history of diversion on the account
- Service has not been disconnected within last 12 months

OPTIONS TO CASH DEPOSITS FOR NON-RESIDENTIAL CUSTOMERS

Based on information provided by the customer, PSO shall consider one of the following options to a cash deposit that will satisfy both the customer and company needs:

- **IRREVOCABLE LETTER OF CREDIT**

Customer may obtain an *Irrevocable Letter of Credit* from banks or other financial institutions. The bank guarantees to pay a specific amount if the customer does not pay the final bill.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 102 - 6
REPLACES SHEET NO. 92 - 6
EFFECTIVE DATE 1/31/11

SCHEDULE: DEPOSIT PLAN

- **SURETY BOND**

  A surety bond may be purchased by the customer from an Oklahoma based Insurance Company. They are normally for the amount of the deposit. Surety Bonds must have an expiration date of not less than 12 months.

- **BILLED DEPOSITS**

  Rather than pay the deposit amount when applying for electric service, the customer may pay the billed deposit with their first electric service bill.

- **INSTALLMENTS ON BILLED DEPOSIT**

  It is possible to arrange to make the billed deposit payments in installments, with partial payment allowed initially and installments not to exceed three consecutive months.

- **DEFERRED DEPOSITS**

  The deposit amount is recorded on the customer's account, but is not charged unless the customer has a past due bill (greater than $10.00) and the account becomes past due at any monthly bill date.

- **REFUNDING DEPOSITS ON ACTIVE NON-RESIDENTIAL ACCOUNTS**

  Non-residential customer service deposits of less than $20,000, with accrued interest, will be automatically refunded after twenty-four (24) months' satisfactory payment of undisputed charges and where payment was not late more than twice; provided, however, that service has not been disconnected within the twenty-four (24) month period. Non-residential customers, who meet the above criteria, must have a minimum of five (5) years continuous service at the service location with PSO before a deposit will be refunded.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SHEET NO. 102 - 7
REPLACES SHEET NO. 92 - 7
EFFECTIVE DATE 1/31/11

SCHEDULE: DEPOSIT PLAN

- **NON-RESIDENTIAL ACCOUNTS WITH INADEQUATE DEPOSITS**

A non-residential customer may be required to post a supplemental deposit amount if PSO determines an inadequate amount exists due to any of the following events: 1) If undisputed charges have become delinquent, with delinquent meaning a payment not received on or before the due date as posted on the bill in two (2) out of the last twenty-four billing periods, or 2) if the customer has had service disconnected during the last twenty-four (24) months, or 3) has presented a check subsequently dishonored.

This plan shall be administered in accordance with the Oklahoma Corporation Commission's established Rules and Regulations.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SHEET NO. 103 - 1
REPLACES SHEET NO. 93 - 1
EFFECTIVE DATE 1/31/11

KIND OF SERVICE: ELECTRIC

SCHEDULE: AVERAGE MONTHLY PAYMENT PLAN (AMP)

For the convenience of our electric service customers, Public Service Company of Oklahoma offers an Average Monthly Payment Plan (AMP) to spread the customer's total annual electric cost over twelve (12) average monthly payments. The AMP Plan is available to residential customers, and when mutually agreeable with Company and customer, to commercial and industrial customers.

The AMP Plan is designed to minimize large seasonal variations in electric service billings by allowing the customer to pay an average amount each month based upon the actual electric usage over the past twelve (12) months. By electing the option of the AMP Plan, customers on fixed income or budgeted finances will benefit through the more nearly consistent payment schedule, which this plan offers. This should serve to minimize credit activity on certain customers due to high billings during summer and winter months.

In order that the customer more fully understand the benefits derived from the AMP Plan, it is important to explain to the customer the basic conditions under which this plan operates. When talking to customers inquiring about the AMP Plan, the following points should be stressed:

1. The customer should understand that the average payment amount is based on the current month's billing, including applicable sales tax, plus the eleven (11) preceding months, divided by twelve (12). The average amount will be the current month's payment under the AMP Plan. At the next billing period, the oldest month's billing history is dropped, the current month's billing is added, and the total is again divided by twelve (12) to find a new average payment amount. The average is recalculated each month in this manner.

2. Monthly variations, upward or downward, may result from fluctuations in fuel cost, variations in usage, and rate changes, but the AMP Plan will serve to minimize large changes due to the averaging of billings over a twelve month period.

3. At the time a customer elects to participate in the plan, the account should be in current status. This means that the current billing should not be past due and no unpaid balance should exist on the account.

4. A customer that is unable to bring the account to a current status may be placed on the plan by using the AMP average amount plus an additional amount, over a specific period of time.

PUBLIC SERVICE COMPANY OF OKLAHOMA
P.O. BOX 201
TULSA, OKLAHOMA 74102-0201
PHONE: 1-888-216-3523

SHEET NO. 103 - 2
REPLACES SHEET NO. 93 - 2
EFFECTIVE DATE 1/31/11

KIND OF SERVICE: ELECTRIC

SCHEDULE: AVERAGE MONTHLY PAYMENT PLAN (AMP)

5. In such instances where sufficient billing history is not available, an AMP account may be established by using an estimated AMP amount average. When sufficient billing history (6 months) has been attained, the system will automatically compute the new AMP amount based on actual billing history.

6. Participation in the plan will have no effect on the Company's approved rate schedules or other billing charges used to calculate the customer's actual monthly billing.

7. Actual billing will continue to be based upon the applicable rate and meter readings obtained to determine consumption. However, the AMP amount will be identified as a separate item on the electric service bill so that the participating customer will know the amount to pay. The actual billing will also be reflected on the bill as a memo item for the customer's information. The unpaid balance referred to as "balance before payment" will appear on the bill. At such time as an AMP account becomes delinquent, a late payment charge may be assessed against the delinquent AMP amount.

8. The difference between actual billings and the averaged billings under the AMP Plan will be carried in a deferred balance that will accumulate both debit and credit differences for the duration of the AMP Plan year--twelve consecutive billing months.

9. At the end of the AMP Plan year (anniversary month), the current month's billing, the eleven (11) preceding months' billing and the net accumulated deferred balance will be summed, and the totals divided by twelve (12) to strike a new average and thereby commence a new AMP Plan year with the average being the first month's billing and required payment under the AMP Plan.

10. Settlement occurs only when participation in the plan is terminated. This happens if an account is final billed, if the customer requests termination, or may be terminated by the Company as a result of past due amounts on an account. The deferred balance (debit or credit) is then applied to the billing now due.

PUBLIC SERVICE COMPANY OF OKLAHOMA **SHEET NO. 103 - 3**
P.O. BOX 201 **REPLACES SHEET NO. 93 - 3**
TULSA, OKLAHOMA 74102-0201 **EFFECTIVE DATE 1/31/11**
PHONE: 1-888-216-3523
KIND OF SERVICE: ELECTRIC

SCHEDULE: AVERAGE MONTHLY PAYMENT PLAN (AMP)

11. The AMP Plan will be offered to residential customers during the months of April and October each year. However, a customer may request participation at any time by telephone, mail, or in person at a Company business office.

Rates Authorized by the Oklahoma Corporation Commission

Effective	Order Number	Cause / Docket Number
January 31, 2011	581748	PUD 201000050
January 29, 2009	564437	PUD 200800144

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

ROCKY MOUNTAIN POWER

ELECTRIC SERVICE SCHEDULE NO. 94

STATE OF UTAH

Energy Balancing Account (EBA)
Pilot Program

AVAILABILITY: At any point on the Company's interconnected system.

APPLICATION: This Schedule shall be applicable to all retail tariff Customers taking service under the terms contained in this Tariff. The collection of costs related to an energy balancing account from customers paying contract rates shall be governed by the terms of the contract. The EBA Pilot Program shall be for a period of approximately four years beginning October 1, 2011, and ending December 31, 2015. This Tariff will also be used to collect the $20 million dollar of deferred net power cost approved in Docket Nos. 10-035-124 and 12-035-67.

DEFINITIONS:

Actual MWh: The actual MWh sold to retail customers recorded in the Company's billing records.

Base MWh: Retail MWh from the most recent general rate case.

EBA (Energy Balancing Account): The mechanism to collect or refund 70% of the accumulated difference between Base EBAC and Actual EBAC.

EBA Annual Filing Date: On or about March 15 of each year.

EBA Carrying Charge: An annual interest rate of 6% simple interest (.50% per month) applied to the monthly balance in the EBA Deferral Account as described in this electric service schedule.

EBA Costs (EBAC): Actual EBAC and Base EBAC include all components of Net Power Cost (NPC) and wheeling revenue, typically booked to the FERC Accounts described in this electric service schedule.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

DEFINITIONS: (continued)

Actual Energy Balancing Account Costs (**Actual EBAC):** The actual Utah NPC and Wheeling Revenues. Adjustments shall be made to Actual EBAC that are consistent with applicable Commission accepted or ordered adjustments, or adjustments called out in a stipulation or settlement agreement, as ordered in the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

Base Energy Balancing Account Costs (Base EBAC): The Utah allocated NPC and Wheeling Revenues approved by the Commission in the most recent Utah general rate case, major plant additions case, or other case where Base EBAC are approved.

EBA Deferral: The monthly amount debited or credited to the EBA Deferral Account. A positive deferral reflects an under-recovery of EBAC and is debited to the EBA Deferral Account. A negative deferral reflects an over-recovery of EBAC and is credited to the EBA Deferral Account.

EBA Deferral Account: FERC Account No. 182.xx. The EBA Account is a balancing account. A positive (Debit) balance means that EBAC have been under collected from customers. A negative (Credit) balance means EBAC have been over collected from customers.

EBA Deferral Account Balance: The EBA Deferral Account Balance from the previous month plus the monthly EBA Accrual less the current monthly EBA Revenue based on the approved EBA Rate plus the monthly Carrying Charge.

EBA Deferral Period: The calendar year prior to the EBA Filing Date. The first EBA Deferral Period shall be the three-month period from October 1 to December 31, 2011.

EBA Rate: surcharge or surcredit applicable to all retail tariff rate schedules and applicable contracts as set forth in this electric service schedule to collect or refund the EBA Deferral Account Balance. The EBA rate will be a percentage applied to the monthly Power Charges and Energy Charges.

EBA Rate Effective Date: On or before November 1 of each year upon approval by the Commission.

EBA Rate Effective Period: 12-month period beginning on the EBA Rate Effective Date.

EBA Revenue: Revenue collected by multiplying the EBA Rate found in the Monthly Bill section of this schedule by the monthly Power Charge and Energy Charge of the Customer’s applicable schedule.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Original Sheet No. 94.3**

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

Net Power Costs (NPC): the sum of costs incurred to acquire power to serve customers less revenues collected from sales for resale. NPC components are those included in the Company's production cost model and recorded in the FERC Accounts described in this electric service schedule.

Wheeling Revenue: Revenues from Transmission of Electricity of Others recorded in the FERC Account described in this electric service schedule.

EBA PROCEDURAL SCHEDULE (Beginning with the 2013 Annual EBA Filing)

1. Rocky Mountain Power will file its application on or about March 15.
2. The Division of Public Utilities will complete its audit report and supporting testimony by July 15.
3. Intervenors may conduct discovery, with a 14 day turn around, beginning March 15.
4. Hearings on the application will be completed by September 15.
5. Any rate change necessary to recover or refund an EBA balance will take effect on or before November 1 of the year the application is filed.

EBA CALCULATIONS AND APPLICATION

APPLICABLE FERC ACCOUNTS: The EBA rate will be calculated using all components of EBAC as defined in the Company's most recent general rate case, major plant addition case, or other case where Base EBAC are approved. EBAC are typically booked to the following FERC accounts, as defined in Code of Federal Regulations, Subchapter C, Part 101, with the noted clarifications and exclusions:

<u>FERC 501- Fuel</u>

FERC Sub 5011000
SAP 515100 – Coal Consumed-Generation (Include)
SAP (all other) – Legal, maintenance, utilities, labor related, miscel O&M (Exclude)
FERC Sub 5013500 - Natural Gas Consumed (Non Gadsby) Natural Gas Swaps (Non Gadsby) (Include)
FERC Sub (All Other) – Property tax, office supplies, Labor, Fuel Handling, Supplies, Maintenance, Start-up Fuel,
Start-up Fuel Diesel, Diesel Fuel Hedge, miscellaneous O&M, Flyash Sales (Exclude)

<u>EBA FERC 501 Adjustments</u>

FERC Sub 5013500
SAP 515200 – Natural Gas Consumed
Gadsby Related Portion of 515200 is transferred to FERC 547(Fuel-Other Generation)
SAP 515220 – Natural Gas Swaps
Gadsby Related portion of 515220 is transferred to FERC 547(Fuel-Other Generation)
SAP 505917– I/C Nat Gas Cons Ker. This SAP account is transferred to FERC
547(Fuel-Other Generation)

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **First Revision of Sheet No. 94.4**
Canceling Original Sheet No. 94.4

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

FERC 447 – Sales For Resale

FERC Sub 4471400
- SAP 301406 – Short-term Firm Wholesale Non Transalta Sales (Include)
- SAP 301409 – Trading Sales Netted-Estimate (Exclude)
- SAP 301410 – Trade Sales Netted (Include)
- SAP 301411 – Bookout Sales Netted (Include)
- SAP 301412 – Bookout Sales Netted-Estimate (Exclude)
- SAP 302751 – I/C ST Firm Whls-Sie (Include)
- SAP 302772 – I/C Line Loss-Nevada (Include)
- SAP 303028 – Line Loss W/S Trading (Include)
- SAP 303100 – Transmission Loss Charge Pass-Through (Exclude)
- SAP 303109 – Transmission Line Loss Rev – Subject to Refund (Include)
- SAP 301409 – Trading Sales Netted – Estimates (Exclude)

FERC Sub 4471300
- SAP 301405 – FIRM Sales (Include)

FERC Sub 4476100
- SAP 304101 – Bookouts Netted – Gain (Include)
- SAP 304102 – Bookouts Netted – Estimates (Exclude)

FERC Sub 4476200
- SAP 304201 – Trading Net- Gains (Include)

FERC Sub 4472000 – Sales for Resale Estimates (Exclude)

FERC Sub 4475000
- SAP 301408 – Off-System Non Firm (Include)

FERC Sub 4479000 – Transmission Services - Utah FERC Customers, Wyo-Pacific Cheyenne (Exclude)

FERC Sub 4471000 – Onsystem Firm - Utah FERC Customers, Wyo-Pacific Cheyenne, Brigham City (Exclude)

EBA FERC 447 Adjustments

1) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
2) SAP 505214 – SMUD Purchases from 555 (Purchased Power) are transferred to 447.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **First Revision of Sheet No. 94.5**
Canceling Original Sheet No. 94.5

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

FERC 555 – Purchased Power

FERC Sub 5552600
SAP 505351 – Electric Swaps G/L (Include)
SAP 505352 – Electric Swaps G/L Estimate (Exclude)
FERC Sub 5551100,1200,1330 - BPA Residential Exchange (Exclude)
FERC Sub 5552500
SAP 505190 – OR Solar Incentive Purchases (Include)
SAP 505206 – Other Energy Purchases, Int (Include)
SAP (All Other) – Exchange Value Purchase, Exchange Value Purchase – Estimate, Purchase Power Expense – Estimate, Renewable Energy Credit Purchase (Exclude)
FERC Sub 5555500
SAP 505207 – IPP Energy Purchase (Include)
FERC Sub 5556200
SAP 304211 – Trading Netted – Loss (Include)
SAP 304213 – Trading Netted – Estimates (Exclude)
FERC Sub 5556300
SAP 505214 – Firm Energy Purchases (Include)
FERC Sub 5556400
SAP 505218 – Firm Demand Purchases (Include)
FERC Sub 5556700
SAP 505215 – Post Merger Imb Charge (Include)
SAP 505220 – Trading Purchases Netted (Include)
SAP 505221 – Bookout Purchases Netted (Include)
SAP 546520 – Operating Reserves Expense (Include)
SAP 505969 – Transmission Imbalance – Subject to Refund (Include)
SAP (All Other) – Bookout Purchases Net – Estimates, Trading Purchases Netted – Estimates, Transmission Imblance Pass-Through Expense, NPC Deferral Accounting Entries, Excess Net Power Cost Amortization Renewable Energy Credit Sales Deferral (Exclude)
FERC Sub 5558000
SAP 505227 – Purchased Power Expense – Under Capital Lease (Exclude)
FERC Sub 5556100
SAP 304111 – Bookouts Netted – Loss (Include)
FERC Sub 5555900
SAP 505224 – Short-Term Firm Wholesale Purchases (Include)
SAP 505931 – I/C ST Firm Pur-Sier (Include)
SAP 505932 – I/C ST Firm Pur-Nev (Include)

EBA FERC 555 Adjustments

1) FERC Sub 5552500
   SAP 505206 – Other Energy Purchases: Remove exchange dollars
2) SAP 301406 - Short-term Firm Wholesale – Transalta Sales are removed from 447 and transferred into 555 (Purchased Power).
3) SAP 505214 – SMUD Purchases are removed from 555 (Purchased Power) and transferred to 447.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **First Revision of Sheet No. 94.6**
Canceling Original Sheet No. 94.6

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

FERC 565 – Wheeling Expense
FERC Sub 5650000
SAP 546530 – ISO/PX Charges (Include)
FERC Sub 5651000
SAP 506010 – Short Term Firm Wheeling (Include)
SAP 506059 – Wheeling Expense Estimate (Exclude)
SAP 506912 – I/C S-T Firm Wheeling Exp-Nevada Pwr (Include)
FERC Sub 5652500,2700,4600 - Non-Firm Wheeling Expense, Pre Merger Firm Wheeling, Firm Wheeling Expense
Firm Wheeling Expense (Trm) (Include)
SAP 506922 – I/C Non-Firm Wheeling Exp-Nevada Pwr (Include)
FERC 503 Steam From Other Sources
FERC Sub 5030000
SAP 515900 –Geothermal Steam (Include)
SAP (All Other) – Labor, materials and supplies, other miscellaneous O&M (Exclude)

FERC 547 Fuel – Other Generation
FERC Sub 5471000 - I/C Nat Gas Cons Ker, Natural Gas Consumed, Nat Gas Exp – Under Capital Lease, Natural Gas Swaps (Include)
EBA FERC 547 Adjustments
FERC Sub 5013500
SAP 515200 – Natural Gas Consumed
Gadsby Related Portion of 515200 (From FERC 501) is transferred to this FERC account (547).
SAP 515220 – Natural Gas Swaps
Gadsby Related portion of 515220 (From FERC 501) is transferred to this FERC account (547).
SAP 505917- I/C Nat Gas Cons Ker. Some of this SAP account was booked originally to FERC 501. This adjustment transfers the amount in 501 to this FERC account (547).

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 | **First Revision of Sheet No. 94.7**
Canceling Original Sheet No. 94.7

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

FERC 456.1 Revenues from Transmission of Electricity by Others

FERC Sub 4561100
SAP 505961 – Transmission Imbalance Penalty Revenue – Load (Exclude)
SAP 505963 – Transmission Imbalance Penalty Revenue –Pt to Pt (Exclude)
SAP (All Other) – Primary Delivery and Distribution Sub Charges, Ancillary Revenue, Use of Facility – Revenue, Transmission Resales to Other Parties, Transmission Revenue Unreserved Use Charges Transmission Revenue – Deferral Fees (Include)
SAP 302831 – I/C Other Wheeling Revenue-Sierra Pac (Inlcude)
FERC Sub 4561600
SAP 301912 – Post-Merger Firm Wheeling Revenue (Include)
FERC Sub 4561910
SAP 301926 – Short-Term Firm Wheeling (Include)
FERC Sub 4561920 – Firm Wheeling Revenue, Pre-Merger Firm Wheeling Revenue, Transmission Capacity Re-assignment revenue and contra revenue, Transmission Point-to-Point Revenue (Include)
FERC Sub 4561930
SAP 301922 – Non-Firm Wheeling Revenue (Include)
FERC Sub 4561990
SAP 301913 – Transmission Tariff True-up (Include)
SAP 302990 – L-T Transmission Revenue – Subject to Refund (Include)
SAP 302991 – S-T Transmission Revenue – Subject to Refund (Include)
SAP 305910 – Ancillary Revenue Sch 1 – Subject to Refund (Include)
SAP 305920 – Ancillary Revenue Sch 2 – Subject to Refund (Include)
SAP 305930 – Ancillary Revenue Sch 3 – Subject to Refund (Include)
SAP 305931 – Ancillary Revenue Sch 3a – Subject to Refund (Include)

Accruals or estimates in accounts 447, 555, and 565 will be excluded; rather, expenses and revenue will be accounted for in the months that they are incurred. Adjustments shall be made to Actual EBAC that are consistent with Commission accepted or ordered adjustments, or adjustments called out in a stipulation or settlement agreement, as ordered in the most recent general rate case, major plant addition case, or other case where Base EBAC are approved.

EBA DEFERRAL: The monthly EBA Accrual (positive or negative) is determined by calculating the difference between Base NPC and Actual NPC as is described below.

$$\textit{EBA Deferral}_{\textit{Utah, month}} = [(\textit{Actual EBAC}_{\textit{month/MWh}} - \textit{Base EBAC}_{\textit{month/MWh}}) \times \textit{Actual MWH}_{\textit{Utah,, month}}] \times 70\%$$

Where:

$$\textit{Actual EBAC}_{\textit{month/MWh}} = [(\textit{NPC}_{\textit{TC, month, actual}} / \textit{Actual MWh}_{\textit{TC, month}}) \times S] + (\textit{WR}_{\textit{Utah, month, actual}} / \textit{Actual MWh}_{\textit{Utah, month}})$$

$$\textit{Base EBAC}_{\textit{month/MWh}} = [(\textit{NPC}_{\textit{TC, month base}} / \textit{Base MWh}_{\textit{TC, month}}) \times S] + (\textit{WR}_{\textit{Utah, month, base}} / \textit{Base MWh}_{\textit{Utah, month}})$$

TC = Total Company

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **Original Sheet No. 94.8**

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

EBA DEFERRAL: (continued)

S = Utah Allocation Scalar, a factor to convert Total Company NPC per MWh to fully allocated Utah NPC per MWh. This is necessary because not all NPC are allocated on the basis of MWh. The Utah Allocation Scalar will be calculated and approved in the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

$WR_{Utah,\ month}$ = Total Company Wheeling Revenue for the month multiplied by the appropriate allocation factors from the most recent general rate case, major plant additions case, or other case where Base EBAC are approved.

EBA Deferral Account Balance: the monthly EBA Account Balance will be calculated as follows:

$$\textit{EBA Deferral Account Balance}_{\textit{current month}} = \textit{Ending Balance}_{\textit{previous month}} + \textit{Deferral}_{\textit{current month}} - \textit{EBA Revenue}_{\textit{current month}} + \textit{EBA Carrying charge}_{\textit{month}}$$

EBA CARRYING CHARGE: the EBA Carrying Charge will be calculated and applied to the monthly balance in the EBA Deferral Account as follows:

$$\textit{EBA Carrying Charge}_{\textit{month}} = [\textit{Ending Balance}_{\textit{previous month}} + (\textit{Deferral}_{\textit{current month}} \times 0.5) - (\textit{EBA Revenue}_{\textit{current month}} \times 0.5)] \times 0.5\%$$

EBA RATE DETERMINATION: Annually, on the EBA Filing Date, Rocky Mountain Power shall file with the Commission an application for establishment of an EBA rate to become effective on the EBA Rate Effective Date of that year. The EBA Deferral Account Balance as of December 31 shall be allocated to all retail tariff rate schedules and applicable special contracts based on the rate spread approved by the Commission. The new EBA rate will be determined by dividing the EBA Deferral Account Balance allocated to each rate schedule and applicable contract by the schedule or contract forecasted Power Charge and Energy Charge revenues. The EBA rate will be a percentage increase or decrease applied to the monthly Power Charges and Energy Charges of the Customer's applicable schedule or contract as set forth in the schedule.

AUDIT PROCEDURES: All items recorded in the EBA Balancing Account are subject to regulatory audit and prudence review. The Division of Public Utilities will complete its audit according to the EBA Procedural Schedule.

(continued)

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

P.S.C.U. No. 50 **First Revision of Sheet No. 94.9**
Canceling Original Sheet No. 94.9

ELECTRIC SERVICE SCHEDULE NO. 94 – continued

MONTHLY BILL: In addition to the monthly charges contained in the Customer's applicable schedule, all monthly bills shall have the following EBA Rate percentage applied to the monthly Power Charge and Energy Charge of the Customer's applicable electric service schedule. The collection of costs related to an energy balancing account from customers paying contract rates shall be governed by the terms of the contract.

Schedule 1	2.15%
Schedule 2	2.15%
Schedule 3	2.15%
Schedule 6	2.69%
Schedule 6A	3.75%
Schedule 6B	2.69%
Schedule 7*	0.92%
Schedule 8	2.93%
Schedule 9	3.43%
Schedule 9A	3.84%
Schedule 10	2.49%
Schedule 11*	0.92%
Schedule 12*	0.92%
Schedule 15 (Traffic and Other Signal Systems)	2.45%
Schedule 15 (Metered Outdoor Nighttime Lighting)	2.47%
Schedule 21	6.70%
Schedule 23	2.17%
Schedule 31	**

* The rate for Schedules 7, 11 and 12 shall be applied to the Charge per Lamp.
** The rate for Schedule 31 shall be the same as the applicable general service schedule.

ELECTRIC SERVICE REGULATIONS: Service under this Schedule will be in accordance with the terms of the Electric Service Agreement between the Customer and the Company. The Electric Service Regulations of the Company on file with and approved by the Public Service Commission of the State of Utah, including future applicable amendments, will be considered as forming a part of and incorporated in said Agreement.

(Continued from Sheet No. 8.030.2)

FUEL COST AND PURCHASE POWER RECOVERY CLAUSE (FUEL):

The monthly charge of each rate schedule shall be rounded to the nearest .001¢ per kilowatt-hour of sales to reflect the recovery of costs of fossil and nuclear fuels and purchased power (excluding capacity payments) for each kilowatt-hour delivered, including other adjustments. Fuel Costs and Purchased Power Recovery Factors are normally calculated annually, for the billing period of January through December and are adjusted to incorporate changes in costs from one period to the next.

ENERGY CONSERVATION COST RECOVERY CLAUSE (CONSERVATION):

The monthly charge of each rate schedule shall be rounded to the nearest .001¢ per kilowatt-hour of sales to reflect the recovery of conservation related expenditures by the Company. The Company shall record both projected and actual expenses and revenues associated with the implementation of the Company's Energy Conservation Plan as authorized by the Commission. The procedure for the review, approval, recovery and recording of such costs and revenues is set forth in Commission Rule 25-17.015, F.A.C. Energy Conservation Cost Recovery Factors are normally developed annually, for the billing period of January through December and are adjusted to incorporate changes in costs from one period to the next.

For non-demand rate schedules, the Energy Conservation Cost Recovery Charge shall be applied to the customer's total kWh. For Demand rate schedules (other than those listed below), the Energy Conservation Cost Recovery Charge shall be applied to the customer's billing demand as specified by the rate schedule. For Rate Schedule CILC-1, the Energy Conservation Cost Recovery Charge shall be applied to the customer's On-Peak demand. For Rate Schedules SST-1 and ISST-1, the Conservation Reservation Demand Charge (RDC) and Daily Demand Charge (DDC) shall be applied to the On-Peak Standby Demand and the Contract Standby Demand as described in sections (2) and (3) of Demand Charge for each rate schedule.

CAPACITY PAYMENT RECOVERY CLAUSE (CAPACITY):

The monthly charge of each rate schedule shall be rounded to the nearest .001¢ per kilowatt-hour of sales or $.01 per kilowatt of demand to reflect the recovery of capacity costs of purchased power, including other adjustments. Capacity Payment Recovery Factors are normally calculated annually, for the billing period of January through December and are adjusted to incorporate changes in costs from one period to the next.

For non-demand rate schedules, the Capacity Payment Charge shall be applied to the customer's total kWh. For Demand rate schedules (other than those listed below), the Capacity Payment Charge shall be applied to the customer's billing demand as specified by the rate schedule. For Rate Schedule CILC-1, the Capacity Payment Charge shall be applied to the customer's On-peak demand. For Rate Schedules SST-1 and ISST-1, the Capacity Reservation Demand Charge (RDC) and Daily Demand Charge (DDC) shall be applied to the On-Peak Standby Demand and the Contract Standby Demand as described in sections (2) and (3) of Demand Charge for each rate schedule.

ENVIRONMENTAL COST RECOVERY CLAUSE (ENVIRONMENTAL):

The monthly charge of each rate schedule shall be rounded to the nearest .001¢ per kilowatt-hour of sales to reflect the recovery of environmental compliance costs as approved by the Florida Public Service Commission. The Environmental Cost Recovery Factor is normally calculated annually, for the billing period of January through December and are adjusted to incorporate changes in costs from one period to the next.

FRANCHISE FEE CLAUSE:

The Monthly Rate of each rate schedule is increased by the specified percentage factor for each franchise area as set forth in the Franchise Fee Factors which are incorporated by reference as part of this clause and as filed with the Florida Public Service Commission. This percentage factor shall be applied after other appropriate adjustments.

(Continued on Sheet No. 8.032)

(Continued from Sheet No. 8.031)

TAX ADJUSTMENT CLAUSE:

The Tax Adjustment Clause shall be applied to the Monthly Rate of each filed rate schedule as indicated with reference to adjustment.

Plus or minus the applicable proportionate part of any taxes and assessments imposed by any governmental authority below or in excess of those in effect on the effective date hereof, which are assessed on the basis of the number of meters; the number of customers; the price of electric energy or service sold; revenues from electric energy or service sold; or, the volume of energy generated or purchased for sale or sold.

Such taxes and assessments are to be reflected on the bills of only those customers within the jurisdiction of the governmental authority imposing the taxes and assessments.

POWER FACTOR CLAUSE:

The Power Factor Clause shall be applied to the Monthly Rate of each rate schedule containing a specified Demand charge. The Customer's utilization equipment shall not result in a power factor at the point of delivery of less than 85% lagging at the time of maximum demand. Should this power factor be less than 85% lagging during any month, the Company may adjust the readings taken to determine the Demand by multiplying the kw obtained through such readings by 85% and by dividing the result by the power factor actually established at the time of maximum demand during the current month. Such adjusted readings shall be used in determining the Demand.