EXHIBIT

Exhibit No.: 303
Issues: Rate Design and Class Cost of Service Study
Witness: David E. Dismukes, Ph.D
Sponsoring Party: Public Counsel
Type of Exhibit: Direct Testimony
Case No.: ER-2014-0370
Date Testimony Prepared: April 16, 2015

MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
OF
DAVID E. DISMUKES

KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ER-2014-0370

Jefferson City, Missouri
April 16, 2015

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 a General Rate Increase for Electric Service.	)))	Case No. ER-2014-0370

AFFIDAVIT OF DAVID DISMUKES

STATE OF LOUISIANA)
)
PARISH OF EAST)
BATON ROUGE)

David Dismukes, of lawful age and being first duly sworn, deposes and states:

1. My name is David Dismukes. I am an expert witness for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

David Dismukes
Expert Witness

Subscribed and sworn to me this 14th day of April 2015.

Notary Public Elizabeth A. Bordelon
Bar # 18127

My Commission expires for life.

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered Limited Liability Company, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also a Professor in the School of the Coast and Environment (Department of Environmental Sciences), the Director of the Coastal Marine Institute (School of the Coast and the Environment), an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), and a member of the graduate research faculty at LSU. Attachment DED-1 provides my academic vita that includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Missouri Office of the Public Counsel ("OPC").

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared 14 Schedules in support of my direct testimony.

Q. WERE YOUR TESTIMONY AND SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by OPC to provide an expert opinion on the Class Cost of Service Study ("CCOSS") and rate design proposed by the Kansas City Power & Light Company ("KCP&L" or "the Company").

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Summary of Recommendations
- Class Cost of Service Study
- Rate Design and Revenue Distribution
- Summary of Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON THE CLASS COST OF SERVICE STUDY.

A. I agree with the use of the Company's CCOSS and recommend that the Commission accept this model, its assumptions, and results as a starting point for setting rates in this proceeding. I have also provided, simply for reference purposes, the results of an alternative CCOSS that utilizes an Average and Excess Demand allocator, where demand is measured using non-coincident peak information (hereafter referred to generally as an "AED-NCP" allocator). The Commission has utilized and approved the AED-NCP allocator in past Ameren Missouri rate cases and I have presented the results for comparison purposes in Schedule DED-3.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My electric rate design recommendations can be summarized as follows:

- The revenue increase should be distributed to the customer classes on an across the board basis at the system average increase.
- Existing customer charges should not be increased in this proceeding.
- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.
- The Residential Other Use rates should be set to the mid-point of the Residential and SGS rates as proposed by the Company.

- The second and third winter rate blocks for the SGS All-Electric rate schedules should be set to the second and third winter rate blocks of the SGS general use schedule consistent with the results of the CCOSS and the Company's proposal.

III. CLASS COST OF SERVICE STUDY

A. INTRODUCTION

Q. WHAT IS THE PURPOSE OF A CCOSS?

A. A CCOSS is a method by which utility costs and revenues are reconciled across different customer classes. The goal of the study is to determine the cost of providing service to either a particular jurisdiction or a particular customer class, and the revenue contribution each makes to cover those costs. The results of a CCOSS produce a rate of return and revenue requirement that can be used as a tool in developing the revenue responsibility and rates for each rate class.

Q. HOW IS A CCOSS PERFORMED?

A. Typically, a CCOSS is performed in three distinct steps: functionalization; categorization; and allocation. The first step in this process, functionalization, simply defines costs based upon their nature. In the specific case of distribution-only electric utilities, most utility costs are associated with providing distribution services, so most distribution-only electric utility costs are identified or functionalized as distribution-related. The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are demand-related, energy-related, or customer-related. The last step of the process "allocates" each of these costs to a respective customer class.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any particular function or category. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and imbued with various interpretations and emphases.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum electricity demands. Electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP").

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount of electricity sold and can be thought of as volumetric-related costs.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. HOW DOES A CCOSS RELATE TO COMMONLY-QUOTED ECONOMIC PRINCIPLES?

A. CCOSSs are also referred to as "fully allocated cost studies" since they allocate test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various jurisdictions and customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for the Company that has accumulated over decades. Rates are, therefore, based upon historic average costs; whereas, economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, distribution utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with a number of joint and common costs, difficult. Added to this problem is the additional fact that the costs utilized by a CCOSS are historic and static, not dynamic and forward looking, undermining many experts' cost causation/pricing claims. There is no single correct answer that is revealed in a CCOSS, and it is often up to regulators to exercise their appropriate judgment regarding the nature of these costs and the implications they have in setting fair, just, and reasonable rates.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS CCOSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those revenues will be recovered, and through which customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether revenues (costs) will be recovered strictly by the peak load contributions of each customer class, or whether the approach will be tempered through the use of peak and off-peak usage considerations. Methodologies that are heavily-biased toward peak considerations (over non-peak or energy), for instance, can tend to prejudice relatively lower load-factor customers, such as residential and small commercial customers, and prefer larger customer classes and off-peak customers. These approaches also fail to capture the basic commodity being sold by the utility, which is electricity, and how the value of that commodity varies by the amount purchased by different customer classes.

Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS.

A. The Company uses five separate allocators to allocate different demand-related cost components: Average and Peak Demand ("AP-4CP") allocator; 12 Coincident Peak Demand ("12CP") allocator; and an allocator derived from maximum non-coincident peak ("NCP") demands at the substation, primary voltage, and secondary voltage levels.

Q. PLEASE DESCRIBE THE COMPANY'S AP-4CP ALLOCATOR.

A. The AP-4CP allocator is a measure of system demands utilizing an average of system average load and peak load. Average and peak allocations are calculated in two parts. First, the peak demand component is determined by each class's peak demand. The Company has used the system's four highest coincident peaks ("4CP"), occurring in the months of June, July, August, and September, as the peak demand component. The energy component is determined by each class's energy (kWh) sales and is apportioned using each rate class's contribution to the total system energy sales (kWh) throughout the study period. The peak demand component is allocated in the same manner as the energy component but instead uses each rate class' contribution to the system's 4CP. The Company weights the energy and demand factors by the load factor and one minus the load factor, respectively. The demand and energy components are combined to derive the final AP-4CP allocator, which in turn is used for allocating production plant assets.

Q. PLEASE DEFINE WHAT IS MEANT BY A "LOAD FACTOR."

A. A load factor is defined as the ratio of the average load in kilowatts supplied during the designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by multiplying the kilowatt hours in the period by 100 and dividing by the product of the maximum demand in kilowatts and the number of hours in the period. A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S 12CP ALLOCATOR?

A. The 12CP allocation relies on the theory that no single monthly peak is more significant than another monthly peak and facilities are installed to meet the utility's constant level of reliability through the year. Therefore, each month's coincident peak demand is considered in the calculation. The Company's CCOSS utilizes a 12CP allocation factor derived by summing the coincident peak demand for all twelve months for each rate class. Next, this value is divided by the total system coincident peak demand for the year. The 12CP allocation is used by the Company for the purpose of allocating transmission plant assets.

Q. PLEASE DESCRIBE THE COMPANY'S NCP DEMAND MEASURE.

A. The Company uses the non-coincident peak allocation method to allocate the portions of the distribution system that have been functionalized and classified to the substation, primary and secondary system and classified as being demand-related. The NCP allocators are a traditional measure of non-coincident customer class peaks measured as the maximum hourly system demand attributable to each rate class for a given year. The NCP allocators utilized in the Company's CCOSS, is used to allocate the demand-related portion of the substation, primary voltage, and secondary voltage distribution system assets that include: Account 360 (Land and Land Rights); Account 361 (Structures & Improvements); Account 362 (Station Equipment); Account 364 (Poles, Towers and Fixtures); Account 365 (Overhead Conductors and Devices); and Account 367 (Underground Conductors and Devices).[1]

Q. PLEASE EXPLAIN HOW THE COMPANY ALLOCATES LINE TRANSFORMERS.

A. The Company allocates Account 368 – Line Transformers using the weighted average of the diversified class demands (NCP) and the undiversified individual customer maximum demands.[2]

Q. DO YOU AGREE WITH THE METHODS AND RESULTS OF THE COMPANY'S CCOSS?

A. Yes and I recommend the Commission accept the Company's CCOSS, and its results, as a starting point for the development of rates in this proceeding.

B. ALTERNATIVE CCOSS AND RECOMMENDATIONS

Q. HAVE YOU RUN THE COMPANY'S CCOSS UTILIZING ANY DIFFERENT DEMAND ALLOCATORS?

A. Yes. I have also prepared a CCOSS, shown on DED-1, which allocates production plant assets using an AED-NCP methodology which has also been recognized as an acceptable method to allocate production plant assets by this Commission and has been used by Ameren Missouri in prior proceedings.[3]

---

[1] Tim Rush, Direct Testimony, 54:4-7.
[2] Tim Rush, Direct Testimony, 54:9-11.
[3] In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase its Annual Revenues for Electric Service, Docket No. ER-2010-0036, Report and Order, Issued May 28, 2010, pg. 87.

Q. PLEASE EXPLAIN HOW PRODUCTION PLANT ACCOUNTS ARE TYPICALLY ALLOCATED.

A. Production plant costs are generally allocated to customer classes consistent with the cost impact that the respective class loads impose on the system. A number of methods can be used to allocate production plant costs including peak demand methods and energy weighting methods. Peak demand methods classify all production plant-related items as demand-related and allocate these costs among customer classes based on the class's contribution to system peak. Some examples of peak demand methods include the single coincident peak method, summer and winter peak method, and twelve-month coincident peak methods. On the other hand, energy weighting methods recognize that energy loads are an important contributing factor of production plant costs and classify a portion of these costs as energy-related. The portion of production plant costs that are classified as energy-related are allocated to customer classes on the basis of class energy usage. Some examples of energy weighting methods are the AED method, "equivalent peaker" method, and peak and average method.[4]

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF PRODUCTION PLANT USING THE AP-4CP METHOD?

A. Yes. The Company's AP-4CP allocation for production plant is an acceptable methodology. As previously stated, energy weighting methods recognize that energy loads are also a contributing factor of production plant costs. The NARUC Cost Allocation

[4] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 41.

Manual recognizes the Average and Peak ("AP") method, as one that may be utilized to allocate production plant.[5] The AP allocator is essentially the average of two numbers and is determined by adding each class's average demand and its contribution to the system peak. The method considers that some production plant costs are incurred in order to provide adequate capacity during peak periods while other production plant costs are incurred as a result of the need to provide energy at all hours of the day. According to the Company's load research data, the highest four consecutive peaks occurred on the utility's system during the summer months of June, July, August, and September. The Company has used these four peaks in the determination of the 4CP demand component of the allocation factor.

Q. PLEASE EXPLAIN THE AVERAGE AND EXCESS ALLOCATION METHOD.

A. The AED allocator is a measure of system demands utilizing an average of system average load and peak load. The method considers the contribution to the system peak by load factor, but does not distinguish between on-peak and off-peak loads with the same load factor. Average and excess allocations are calculated in two parts. The first component, average demand (calculated by taking total kWh sales and dividing by the total number of hours in the study period) is multiplied by the load factor. The second component, excess demand, is calculated by taking the difference between a measure of system peak demand and average demand by rate class. The excess component is then

[5] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 57.

multiplied by one minus the total system load factor. These two allocation factors (average demand and excess demand) are added together to derive the final allocator.[6]

C. CCOSS RECOMMENDATIONS

Q. DO YOUR ALTERNATIVE CCOSS STUDIES CHANGE THE CLASS RATES OF RETURN?

A. Yes. The results of the alternative CCOSS is compared to the Company's original CCOSS results in Schedule DED-2.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I recommend the Commission accept the Company's CCOSS, and its results, as a starting point for the development of rates in this proceeding. I have also prepared an alternative CCOSS that utilizes an AED-NCP allocation method for production plant. These methods (the Company's proposed approach and the AED-NCP approach) have been utilized by the Company in past proceedings and by other Missouri electric utilities. The results of the two studies, however, do not produce significantly different results, hence my recommendation to accept the Company's proposed CCOSS.

D. CUSTOMER CHARGES

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS?

---

[6] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p 49.

A. Yes. A summary of the Company's current and proposed customer charges are provided in Schedule DED-8. The Company proposes to increase residential customer charges to a level that the Company notes will recover almost all of the residential class' customer and local distribution-related costs.[7] Under the Company's proposal, commercial and industrial customer charges will increase at the system overall percentage increase of 16 percent.[8]

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CLASS COST OF SERVICE STUDY?

A. The customer charge revenues associated with the Residential class, including Residential All-Electric (one meter); Residential All-Electric (two meters), Residential Other Use; Residential Time-of-Day; and Residential Smart Grid customers, are about nine percent of the Company's estimated class revenue responsibilities. A summary of this information is provided in Schedule DED-10.

Q. WHAT IS THE IMPACT OF THE COMPANY'S RECOMMENDATION ON THE RESIDENTIAL CLASSES?

A. The Company proposes to increase the customer charge for the Residential class from $9.00 to $25.00, an increase of $16.00 per month, or close to 178% percent increase for those customers. Additionally, the Company proposes to increase the additional meter charge for residential space heating customers from $2.05 to $5.00, an increase of $2.95 per month, or approximately 144% increase. The Company recommends

[7] Tim Rush, Direct Testimony, 65:9-10.
[8] Tim Rush, Direct Testimony, Schedule TMR-9.

increasing the customer charges for the Small General Service and the remaining customer classes by about 16 percent.[9]

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES COMPARE TO OTHER ELECTRIC DISTRIBUTION COMPANIES?

A. Schedule DED-9 provides a survey of current residential and small commercial customer charges for major electric companies operating in the Mid-West region.[10] The Company's proposed Residential customer charge of $25 per month is significantly higher than the average residential system charge of $8.87 for the surveyed Mid-West region utilities. There is not a single electric utility in the survey that has a residential customer charge greater than the Company's proposal.

Q. HOW DOES THE CURRENT RESIDENTIAL CUSTOMER CHARGE COMPARE TO OTHER DISTRIBUTION COMPANIES?

A. The Company's current residential customer charge of $9.00 is slightly higher than the average residential customer charge of $8.87 for the surveyed Mid-West region electric utilities. Of the 58 utilities surveyed, one utility has a customer charges equal to the Company's residential customer charge, 36 electric utilities have customer charges lower than the Company does and 20 have a customer charge higher than the Company's current charge.

Q. WHAT ABOUT THE SMALL COMMERCIAL CUSTOMER CHARGES?

---

[9] Tim Rush, Direct Testimony, Schedule TMR-9.

[10] The Midwest region includes Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, South Dakota, and Wisconsin as defined by the U.S. Census Bureau.

A. The Company's proposed small commercial customer charge of $19.06 per month is higher than the average small commercial customer charge of $13.50 for other regional utilities. In addition, 46 out of 58 electric companies (79 percent) have customer charges lower than the Company's proposal. Compared to the current customer charge of $16.45, 39 out of the 58 or 67 percent of the electric companies have a lower customer charge.

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed, variable, block, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges need not strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge equals fixed cost" dogma gets repeated so often that it can drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

Q. DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH SYSTEM OR CUSTOMER CHARGES?

A. Yes, and that has been provided on Schedule DED-12. "Customer-related" expense accounts are those typically allocated on the basis of customers and include: removing and setting meters; maintenance of meters; services expense; maintenance of services; meter reading expense; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the services and meter plant accounts and property taxes as well as the carrying charges, at the Company's requested rate of return, for the customer portion of services investment and 100 percent of the meters investment.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. In most cases, the Company's current customer charges are insufficient to recover commonly-recognized customer costs. The Residential classes' customer-related costs per customer are $13.54 compared to the current customer charge revenue per customer of $9.16. The Small General Service class is estimated to have customer-related costs at $22.06 per customer compared to its current customer charge revenue per customer of $18.25. On the other hand, the Large General Service class's customer-related costs per customer are $142.14 compared to the current customer charge revenue of $178.53.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINED THE PROPOSED CUSTOMER CHARGE FOR THE RESIDENTIAL CLASS.

A. The Company has used its proposed CCOSS in the determination of the residential customer charges.[11] However, the Company analysis includes costs associated with the local facilities demand-related distribution costs, not just those typically considered as being customer-related.[12] In other words, the Company's definition of "costs" is a combination of both customer and demand-related expenses, as opposed to those that are simply customer-related alone. According to the Company's CCOSS, the monthly customer component for the Residential class is $13.54 and the local facilities demand distribution component is $12.40. The Company has combined these two cost components to arrive at the recommended $25.00 per month residential customer charge.

Q. IS THE COMPANY PROPOSING TO INCORPORATE THE LOCAL FACILITIES DEMAND DISTRIBUTION COMPONENT INTO THE CUSTOMER CHARGES OF THE COMMERCIAL AND INDUSTRIAL CUSTOMER CLASSES?

A. No. The Company is not proposing to collect the local facilities demand costs as a customer charge component for the Commercial and Industrial classes. These classes currently receive a facilities demand charge which is used to collect the costs associated with the local demand distribution facilities. The facilities demand charge is a per kW charge similar in design to the standard demand charge assessed to the Commercial and

[11] Company's response to OPC Discovery Request 0039.
[12] Tim Rush, Direct Testimony, 65:9-10.

Industrial customers. Residential customers are often not assessed a demand charge, such as the facilities demand charge proposed in this case, because their meters do not have demand metering capabilities in contrast with the meter capabilities of the Commercial and Industrial customers.

Q. HAS THE COMPANY INCLUDED THE LOCAL FACILITIES DISTRIBUTION DEMAND COMPONENT IN ITS PROPOSED RESIDENTIAL CUSTOMER CHARGES IN THE PAST?

A. No. My review of the last five rate cases filed by the Company revealed that in not a single one of those cases did the Company propose to include the local facilities demand component in any of the proposed residential customer charges. In fact, in the previous five rate cases, with the exception of ER-2006-0314, the Company proposed to increase customer charges for the residential class on an equal percentage basis to the overall increase.[13] In case ER-2006-0314, the Company proposed a slightly higher increase of roughly $2.25 to the then residential customer charge of $6.11, an increase of about 37 percent.[14] However, as previously mentioned the rate design issues in that proceeding were settled resulting in customer charges that were increased across-the-board at the overall percent increase of 12.6 percent for the residential class.[15]

---

[13] See the Direct Testimony of Tim Rush in case numbers: ER-2006-0314; ER-2007-0291; ER-2009-0089; ER-2010-0355; and ER-2012-0174.

[14] In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan, Docket No. ER-2006-0314, Direct Testimony of Tim Rush, Exhibit TMR-1, p. 1.

[15] In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Begin the Implementation of Its Regulatory Plan, Docket No. ER-2006-0314, Report and Order, Issued December 21, 2006, Exhibit D, Appendix A p. 1, ¶ 5.

Q. HAS THE COMPANY EXPLAINED WHAT COSTS ARE ASSOCIATED WITH THE LOCAL DISTRIBUTION FACILITIES DEMAND COMPONENT?

A. Yes. The Company has stated:

> The facilities charges included in commercial and industrial tariffs conceptually reflect the cost of transmission plant and distribution plant assets necessary to provide electric service to customers. Analysis supporting the rate design case in the late 1990's based the facilities charge on costs in Plant accounts 350-368. However, rate adjustments resulting from subsequent rate cases have been applied more generally, often on an even percentage basis to all rate components, affecting the facilities charge's relationship to these costs.[16]

The Company references the commercial and industrial customers in their response but does not mention how the local facilities demand costs relate to smaller customers like the residential class. Furthermore, the Company indicates that over time due to the nature of the applied increase that the current facilities charges do not necessarily represent the costs they are intended to recover.

Q. DO YOU AGREE WITH THE COMPANY'S INCLUSION OF THE LOCAL FACILITIES DISTRIBUTION DEMAND COMPONENT IN THE CUSTOMER CHARGE?

A. No. The customer charge should not include costs typically classified as demand-related. When designing rates a number of ratemaking objectives must be considered such as gradualism, rate continuity, and policy considerations. There is no pre-defined, universally-accepted formula for developing rates and judgment used to develop rates that meet policy objectives. As a consequence of ratemaking objectives and limitations

[16] Company's Response to OPC Discovery Request 84.

in metering equipment, it is often the case that demand-related costs are often recovered through the energy charge for smaller customers. Demand charges are used with Commercial and Industrial customers, but rarely for Residential customers.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL?

A. No. Moving the local facilities demand-related costs into the customer charge will not better align rates as asserted by the Company, rather the inclusion of these costs in the customer charge merely shifts the revenue recovery risk from the Company to the residential ratepayers.[17] The Company's proposal to collect the local facilities demand distribution component as a fixed monthly customer charge assumes all residential customers have the same level of demand, which is an incorrect assumption. Therefore, it fails to collect costs in the manner in which they are incurred. Usage is more closely related to what causes demand-related costs to be incurred than the mere existence of a customer.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. My specific customer charge recommendations are provided on Schedule DED-14. I recommend no increase in the customer charges in this proceeding. As shown in my survey of current customer charges in the Mid-west provided in DED-9, over half of the utilities surveyed have customer charges at the same rate or lower than KCP&L's current Residential customer charge. Additionally, my analysis provided in DED-12 shows that the current customer charges collect 68 percent of the total customer related

---

[17] Tim Rush, Direct Testimony, 64:3-4.

costs. Furthermore, the Commission ordered in the Company's last rate case that any increase in residential rates should not apply to the residential customer charges.[18] Therefore, it is my opinion that an increase in customer charges is not necessary in this proceeding.

IV. RATE DESIGN AND REVENUE DISTRIBUTION

A. RATE DESIGN OBJECTIVES

Q. WHAT ARE SOME OF THE GUIDING CRITERIA OR PRINCIPLES UPON WHICH RATE DESIGN SHOULD BE BASED?

A. There are several generally accepted rate design principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used in order to protect customers from rate shock.
3) Rate continuity should be maintained whenever possible.
4) Rates should be informed by costs, however in some instances class cost of service results may not be the only factor used in rate development.
5) Rates should be transparent and comprehensible to customers.

[18] In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service; File No. ER-2012-0174, Report and Order, Issued January 9, 2013, p. 40.

Q. HOW ARE THE ABOVE CRITERIA BLENDED TO DEVELOP RATES FOR A REGULATED UTILITY?

A. While each of the earlier-mentioned principles is important, the weight of any one principle can change depending upon the relative importance of certain policy goals. Optimal rate design should balance policy goals such that final rates are fair, just, and reasonable. Because there is no pre-defined, universally-accepted formula for developing rates, judgment is often necessary in formulating a rate design that meets these policy objectives.

Q. HAS THE COMMISSION COME TO SIMILAR RATE DESIGN CONCLUSIONS?

A. Yes. The Commission has clearly recognized many of these principles in past rate cases, explicitly expressing concerns about balancing gradualism and rate continuity objectives against those objectives intended to provide a utility with an opportunity to earn fair return. The Commission has also recognized the importance of a CCOSS as one of several important inputs in the development of rates. The Commission, however, has clearly noted in prior decisions that it will not be bound to strict adherence to cost of service outcomes in setting rates.[19]

Q. HAS THE COMMISSION EXPRESSED ANY PRIOR PREFERENCES IN ALLOCATING COSTS TOWARD VARIABLE AS OPPOSED TO FIXED CHARGES?

A. Yes. The Commission has noted in a prior decision that there are instances where the allocation of costs towards variable, as opposed to fixed, charges is preferable. The

[19] In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service, Case No. ER-2012-0166, Report and Order, December 12, 2012, p. 110.

Commission justified this position primarily on important customer sovereignty considerations: customers have greater control of their bills when charges are leveraged more heavily to variable, as opposed to fixed charges.[20] According to the Commission, weighting charges more heavily to variable, as opposed to fixed charges, also sends better energy efficiency and conservation signals to ratepayers. [21]

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN PROPOSALS.

A. The Company proposes to: (1) increase jurisdictional rates by approximately $120.9 million; (2) increase customer charges;[22] and (3) shift pricing from the winter season to the summer season consistent with the results of the CCOSS.

B. REVENUE DISTRIBUTION

Q. PLEASE EXPLAIN THE PROCESS BY WHICH CLASS REVENUE RESPONSIBILITIES ARE DETERMINED.

A. The revenue distribution process is typically an attempt to reconcile the strict, class-specific results of the CCOSS with many of the rate design policy goals discussed earlier. For instance, the CCOSS may indicate one, or several classes' revenue responsibility is far in excess of the proposed overall average increase in rates. In other words, the strict results of the CCOSS may show that a particular class may warrant a very large increase in rates in order to bring revenues closer to that class' estimated full

[20] In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Commission Order, January 9, 2013, p. 40.
[21] In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service; File No. ER-2012-0166, Report and Order, Issued December 12, 2012, pp. 110-111.
[22] Tim Rush, Direct Testimony, 58:11-23.

cost of service. This significant percent increase in rates, however, may violate rate gradualism policies. Thus, some intermediate step needs to be conducted that uses the CCOSS to "inform" policy as to the direction of the rate increase, but conditions that increase to conform to other ratemaking policy goals. This intermediate step is typically done in the revenue distribution process. The revenue distribution process, in turn, often uses a variety of subjective "rules" (or formulaic approaches) to allocate class revenue increases in a fashion that moves rates closer to costs, but conditions those increases to minimize rate shock and ensure policy equity.

Q. HOW DID THE COMMISSION DISTRIBUTE THE REVENUE INCREASE IN THE LAST CASE?

A. In the Company's last rate proceeding, the Commission ordered that any increase in rates be applied equally to all rate classes.[23] Additionally, the Commission agreed with OPC's recommendation regarding revenue neutral adjustments and ordered the shift of revenue from the over-earning SGS and MGS rate classes to the under-earning LP class in order to bring these classes closer to the system return.[24]

Q. HOW DID THE COMMISSION ESTABLISH RATES AND CHARGES IN THE COMPANY'S LAST RATE CASE?

[23] In the Matter of the Kansas City Light & Power Company Request for Authority to implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Report and Order, Issued January 9, 2013 p 36.

[24] In the Matter of the Kansas City Light & Power Company Request for Authority to implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Report and Order, Issued January 9, 2013 p 38.

A. The Commission ordered that any increase should be distributed equally to all rate components for all rate classes. However, the Commission ordered that the residential class rate increase was to be allocated exclusively to the (volumetric) energy charge with no increase assigned to the (fixed) customer charge.[25] Additionally, in order to gradually move winter rates to recover winter costs the Commission found that some additional increases were necessary for the first winter block of the Residential All Electric class and winter season separately metered space heat rate of Residential All Electric-2 meter class. Both of these rate blocks were increased by an additional five percent.[26]

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION IN THIS PROCEEDING.

A. The Company proposes an across the board increase to all classes at the system average increase.[27]

Q. WHAT RATE DESIGN RECOMMENDATIONS IS THE COMPANY MAKING?

A. The Company makes several rate design recommendations. Specifically, it recommends:

- Aligning the fixed/variable relationship within the residential class by moving certain costs currently recovered in the volumetric charge to the customer charges:

[25] In the Matter of the Kansas City Light & Power Company Request for Authority to implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Report and Order, Issued January 9, 2013 p 40.
[26] In the Matter of the Kansas City Light & Power Company Request for Authority to implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Report and Order, Issued January 9, 2013 p 39.
[27] Tim Rush, Direct Testimony, 58:12-13.

- Shifting some cost recovery from the winter season to the summer season, for the residential class, in order to be uniform consistent with the CCOSS.
- Appling an equal percentage increase to all rate components for the Commercial and Industrial rate classes.
- Adjusting certain All-Electric rate components to make those components consistent with comparable rate components included in the General Use rate.
- Ensuring that all rate classes (except lighting classes) receive an increase of at least 25 percent of the overall average increase due to non-energy efficiency related costs.
- Freezing or eliminating Special rates which are no longer used or functional.
- Cleaning up obsolete rates for the Lighting classes, in addition to adding a kWh usage to the tariff in support of the proposed Energy Cost Adjustment.[28]

Q. PLEASE DESCRIBE A RELATIVE RATE OF RETURN AND HOW IT CAN BE USED IN DISTRIBUTING A UTILITY'S RATE INCREASE.

A. A "relative rate of return" ("RROR") is simply the ratio of a given class' estimated rate of return to the overall system rate of return. This ratio can also be thought of as a "unitized" rate of return since each class' estimate return is standardized to the Company's overall request. For example, if the residential class is estimated to be earning 11 percent from the CCOSS, and if the Company is requesting a 10 percent overall rate of return, then the residential class can be said to have a RROR of 1.10 (i.e., 11 percent divided by 10 percent). RRORs can also be thought of as a special type of index number measuring a specific class' return relative to the Company's overall rate of

[28] Tim Rush, Direct Testimony, 58:17-23, 59:1-22.

return. Thus, classes with a relative rate of return greater than 1.0 entails that those classes are likely earning an amount greater than the Company's overall rate of return. Those classes with a relative return below 1.0 can be said to be earning an amount less than the Company's overall rate of return. Schedule DED-4 presents the Company's estimated class relative rates of return under its current and proposed rates.

Q. HAVE YOU PREPARED A COMPARISON OF THE RROR IN THE LAST RATE PROCEEDING RELATIVE TO THE COMPANY'S ESTIMATES IN THIS PROCEEDING?

A. Yes. Schedule DED-5 provides a comparison of the RRORs from the 2012 rate case and those filed in this proceeding. The residential class RRORs decreased from 0.98 (prior case) to 0.74 in the current rate case. The Large General Service ("LGS"), Large Power Service ("LPS") and combined Lighting classes are all earning RRORs higher than the prior rate case.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend an across the board increase to all classes at the system average increase. The results of my recommended revenue distribution using the Company's revenue requirement are shown on Schedule DED-6. I have also prepared a recommended revenue distribution with a revenue requirement that includes the Staff's accounting adjustments as well as the adjustments proposed by Public Counsel, which is shown on DED-7.

C. RATE DESIGN

Q. PLEASE EXPLAIN THE COMPANY'S RATE PROPOSALS IN THIS PROCEEDING.

A. The Company is proposing a number of changes for the residential classes. The majority of these changes are intended to align fixed and variable costs within the classes rate structure. Additionally, the Company is proposing to adjust the summer and winter energy rates for the residential classes in order to "reinforce seasonal price differentials."[29] The Company states that the current rate structure has a large amount of the fixed costs being recovered through the volumetric rates.[30] Therefore, it is proposing that this relationship be modified to "improve the alignment but not to achieve straight fixed variable pricing."[31] The Company further states that its current pricing approach is "wrong" and "distorts the price of electricity;"[32] putting the Company at risk of under-recovery of revenues as a result of reductions in usage, "driven by reduced customer growth, energy efficiency, or even customer self-generation."[33] The Company asserts that it is in support of a "balanced" rate design that achieves the movement towards recovery of fixed costs through the customer charges, as well as redesign of seasonal elements that reflect the higher cost of energy during the summer peak periods.[34] The Company is not proposing to adjust any comparable "misalignments" between fixed and variable charges for the Commercial and Industrial ("C&I") rate classes given what the Company describes as "greater risks to changing the C&I rates."[35] A summary of the Company's current and proposed rates and customer charges has been provided in Schedule DED-14.

---

[29] The Direct Testimony of Tim Rush, 65:12-16.
[30] The Direct Testimony of Tim Rush, 61:3-5.
[31] The Direct Testimony of Tim Rush, 64:3-4.
[32] The Direct Testimony of Tim Rush, 64:14-15.
[33] Tim Rush, Direct Testimony, 63:8-9.
[34] Tim Rush, Direct Testimony, 64:7-10.
[35] Tim Rush, Direct Testimony, 70:17.

Q. PLEASE EXPLAIN THE "RISK" THE COMPANY IS REFERRING TO IN CHANGING THE C&I CUSTOMER'S RATES.

A. The Company has stated that at this time it is uncertain of the impact that re-designed rates will have on the C&I customers.[36] Currently, C&I customers have the ability to move between rates selecting the best rate for their individual usage and load characteristics.[37] Any changes that the Company makes to the current rate structure of the C&I customer classes can affect the switching rates of these customers, potentially causing the Company to incur lost revenues.[38] The Company cannot reliably predict how rate changes to this class will impact the customer rate switching. Therefore, they have recommended not to make significant adjustments to the C&I rate classes.

Q. PLEASE EXPLAIN THE COMPANY'S RESIDENTIAL CLASS RATE DESIGN PROPOSALS.

A. The Company has various rate schedules that apply to residential customers and is proposing to increase customer charges for each of these residential rate schedules by moving a portion of the costs currently recovered through the volumetric rate into the fixed monthly customer charge.[39]

Q IS THE COMPANY PROPOSING RELATIVELY LARGE CUSTOMER CHARGE INCREASES FOR THESE RESIDENTIAL RATE SCHEDULES?

---

[36] Tim Rush, Direct Testimony, 70:21-22, 71:1.
[37] Company's Response to OPC discovery request 53.
[38] Tim Rush, Direct Testimony, 70:20-21.
[39] Tim Rush, Direct Testimony, 58:17-19.

A. Yes. The Company is proposing to increase residential customer charges by 178 percent from $9.00 to $25.00. Summer volumetric rates will be increased and winter volumetric rates will either be reduced or remain at their current levels. [40] The Residential Time of Day ("TOD") class will also see an increase in the customer charge from $14.04 to $25.00—an increase of 78 percent. The summer volumetric charge will also increase by about 16 percent in order to collect the remaining class revenue requirement; the winter volumetric rate will remain unchanged. Although, the Company is proposing to restructure the energy rates, all of the revenue increase assigned to the Residential class will be recovered through the proposed increase to the customer charges.[41]

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO REVISE THE ENERGY PRICING OF THE RESIDENTIAL OTHER USE RATE.

A. The Company states that it is revising the energy pricing for this tariff to "better align it with the Residential and Small General Service rates."[42] According to the Company this is done by calculating the average rate between the first rate block of the Residential General Use class and the first rate block of the SGS-Secondary class. After the average rate was determined the Company applied the overall increase of 16 percent to arrive at the new rate. The Company has stated that the Residential Other Use rates when conceived were set between the first rate block of the residential class and the first rate block of the SGS rate class.[43]

[40] Tim Rush, Direct Testimony, 65:12-13.
[41] See Company's workpaper titled "MO-Res-RD".
[42] Tim Rush, Direct Testimony, 66:3-4.
[43] Company's response to OPC discovery request 67.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL FOR THE RESIDENTIAL OTHER USE VOLUMETIRC RATE DESIGN?

A. Yes. The Residential Other Use rate schedule serves loads that are not connected to the customer's dwelling, such as well pumps, garages, and workshops, but are nevertheless associated with residential customer usage.[44] Therefore, realigning the rates to reflect their original design is acceptable.

Q. WHAT CHANGES IS THE COMPANY PROPOSING WITH RESPECT TO THE SMARTGRID TOU RATES?

A. The Company's SmartGrid TOU rates expired at the end of December 2014. Customers currently taking service on this tariff will revert to their generally-available rates.[45] The Residential SmartGrid TOU rates were established only for the duration of the SmartGrid Demonstration Area Pilot. The Company indicates that any future SmartGrid-related or TOU rate will be implemented separately through a general rate proceeding or special tariff filing.[46]

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO RESIDENTIAL TOD RATES?

A. The Company is recommending that this tariff be closed to any future participation based upon the Company's position that the tariff "only has 38 customers and does not

[44] Tim Rush, Direct Testimony, 66: 4-7.
[45] Tim Rush, Direct Testimony, 66:9-11.
[46] Company's response to OPC discovery request 62.

perform as it should."[47] The Company also notes that the on-peak and off-peak rates, as well as the definitions of the peak time periods, have not been validated since 2005.[48] The Company believes a better designed rate would provide more value to customers as well as the Company and should achieve a better participation rate than 38 customers.

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION TO PERMANENTLY FREEZE THE RESIDENTIAL TIME OF DAY RATES?

A. No. The Company clearly admits that the current rate design for this tariff is poor and could be improved, yet fails to offer any improvements, of any type for this specific service offering. The Company effectively punts the issue of the tariff/rate design deficiency to another day by suggesting the development of a new rate schedule at some undefined point of time in the future. The Company's proposal is also incongruous with its earlier-stated rationales of trying to send better price signals to customers through a complete re-working of the manner in which it sets its residential customer charges. The Company, on the one hand, proposes to dramatically change the way residential customers are billed for a component of their facilities costs, to better align the rate structure with costs, but is less interested in re-working an existing tariff that is more granularly structured to, at least in theory, reflect cost changes across the various hours of the day. The Commission should reject the Company's TOU rate proposal and require the Company to re-file a modified and improved TOU tariff in its next rate case.

[47] Tim Rush, Direct Testimony, 66:8-9.
[48] Company's response to OPC discovery request 50.

Q. PLEASE EXPLAIN THE COMPANY'S SMALL GENERAL SERVICE (SGS) RATE DESIGN PROPOSALS.

A. The rate schedule for the Small General Service class consists of three components: a fixed customer charge, a facilities demand charge, and an energy charge. The Company proposes to increase the customer charge by about 16 percent from $16.45 to $19.06. The remaining amount of revenue is apportioned to the facilities charge and the energy charge. Additionally, the Company is proposing to "correct" some of the rate components of the All-Electric rates which were priced higher than the same rate component within the General Use rate.[49] The Company is proposing to set the second and third winter rate blocks of the SGS All-Electric Primary and Secondary rate schedules equal to the rate blocks under the SGS General Use tariff.

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED ADJUSTMENT TO THE WINTER RATE BLOCKS OF THE SGS ALL-ELECTRIC PRIMARY AND SECONDARY RATE SCHEDULES?

A. Yes. Generally, an all-electric customer will have a higher load factor than its general use counterpart (customers that do not use electricity for heating), revealing that these customers have more efficient use of the utility's electric system and in theory indicating a lower cost to serve. The CCOSS shows that the $/kWh for these two rate classes are almost equal, however, the SGS All-Electric classes experience a slightly

[49] Tim Rush, Direct Testimony, 70: 8-11.

lower cost. The CCOSS shows a difference of $0.0001/kWh between the SGS general use and SGS All-Electric rate schedules.

Q. IS THE COMPANY'S PROPOSED RATE DESIGN, SPECIFICALLY THE PROPOSAL TO SIGNIFICANTLY INCREASE THE CUSTOMER CHARGE, CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. No, the Company's rate design proposals are inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable. As an example, in the extreme case of a Straight Fixed Variable ("SFV") rate design, customers will pay the same charge regardless of their usage level. As a result, inefficient customers would pay the same monthly utility bill as relatively more efficient customers, negating all incentive to seek greater efficiency.

Q. HAS THE COMMISSION ACKNOWLEDGED THE CONTRADICTORY RELATIONSHIP THAT FIXED CUSTOMER CHARGES HAS ON ENERGY EFFICIENCY?

A. Yes, the Commission rejected a prior-type of proposal for another jurisdictional utility (Union Electric Company d/b/a Ameren Missouri) noting that:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity.
>
> Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would

> send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[50]

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT THAT INCREASED FIXED CHARGES CAN HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage. Specifically, it stated:

> ...we concur with OPC that residential customer charges should not be increased at this time. Consistent with this decision, we reject BGE's proposal to increase either residential or non-residential customer charges. This decision will afford ratepayers a better opportunity to control their monthly bills by controlling their energy usage. This decision is consistent with EmPOWER Maryland goals and with our decision in BGE's last base rate case.[51]

Q. IS THE MARYLAND COMMISSION ALONE IN ITS OBSERVATION THAT HIGH FIXED CHARGES DISCOURAGES ENERGY EFFICIENCY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") found decoupling as one of three major approaches to delink utility revenues from sales. One alternative listed was SFV rate design, which attempts to assume most all utility costs into fixed

---

[50] In the matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service; File No. ER-2012-0166, Report and Order, Issued December 12, 2012, pp. 110-111.
[51] In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9326. Order No. 86060, Issued December 13, 2013, p. 105.

monthly charges. The NARUC research noted this type of rate design to be problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[52]

Q. HAS THE COMPANY CONDUCTED ANY ANALYSIS THAT ATTEMPTS TO EXAMINE HOW ITS CUSTOMER CHARGE PROPOSALS MAY IMPACT CUSTOMER AFFORDABILITY?

A. No, the Company indicates that it has performed no specific analyses regarding the impacts that its rate design proposals may have on customer affordability.[53]

Q. HAVE YOU PREPARED ANY RESIDENTIAL TYPICAL BILL ANALYSES ASSOCIATED WITH THE COMPANY'S RATE DESIGN PROPOSALS?

A. Yes. Schedule DED-13 illustrates various total distribution bill changes for residential customers of varying monthly kWh usage levels. Three types of illustrative customers are identified in this analysis. Customer 1 represents a customer taking service under the standard residential service class who uses an average of 825 kWh per month. Customer 2 represents a smaller customer using an average of only 550 kWh per

[52] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 5. Emphasis added.
[53] Company's Response to OPC Data Request 44.

month, approximately a third less than the hypothetical system average. Customer 3 likewise represents a larger customer using an average of 1,100 kWh per month, approximately a third more than the hypothetical system average. The schedule shows that customers using close to the system average will see an increase of 18.8 percent in the summer months and 12.4 percent during the winter months. Those customers using greater than average use will actually incur a slightly less increase of 15.5 percent and 12.0 percent during the summer and winter, respectively. Low-use residential customers will see their rates increase by as much as 25.1 percent during the summer and 13.7 percent during the winter. Schedule DED-11 also includes the remaining residential rate classes which will experience a similar trend in bill increases as the standard residential customer class.

D. VOLUMETRIC CHARGES

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S VOLUMETRIC DISTRIBUTION RATE PROPOSALS?

A. Yes. For most classes, the Company proposes to recover the remaining portion of a class' revenue requirement through the energy charges. However, for those classes that also have a demand charge, the demand charge is increased across-the-board at about 16 percent--the system average increase. The exception is the Company's proposed change to the winter demand charge for the MGS All Electric Primary and Secondary rate schedules. The Company is proposing to decrease these demand charges and set them equal to the winter demand charges of the standard MGS Primary and Secondary rate schedules. The remaining revenue requirement is recovered through the energy charge. In most rate classes, energy charges are increasing by an amount about equal to the overall increase except in the instances where the Company is recommending to decrease rate blocks within the various rate classes.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO MAKE ADJUSTMENTS TO CERTAIN VOLUMETRIC RATE ELEMENTS FOR THE RESIDENTIAL RATE CLASSES.

A. As previously discussed, the Company is proposing to make several "corrections" to certain volumetric rate elements within the Residential rate classes. The Company proposes to reduce the winter energy rates for the General Residential and Residential All-Electric (two meter) Schedules. These rates will be decreased by half of the difference between the same rate blocks occurring under the Residential All-Electric (one meter) rate class. Additionally, in regard to the Residential All-Electric (two meter) class, the Company proposes setting the separately metered space heat rate equal to the third winter rate block under the Residential All-Electric (one meter) rate schedule. Currently, this rate block is set higher than the third rate block of the all-electric one meter customer. The Company is also proposing to add a second rate block to the winter rate block structure under the Residential All-Electric (one meter) class. This rate is proposed to be set equal to the second rate block of the Residential general use and Residential All-Electric-two meters rate.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO MAKE ADJUSTMENTS TO CERTAIN VOLUMETRIC RATE ELEMENTS FOR THE REMAINING RATE CLASSES.

A. The Company is proposing to re-design the volumetric rate blocks for all the remaining rate classes except the Large Power Service and Lighting classes. The Company proposes to set the second and third rate blocks for the Small General Service All-Electric Primary and Secondary rate classes to the second and third rate blocks under the General SGS Primary and Secondary rate schedules. Additionally, the SGS separately metered space heat rate will be set to the third block of the General SGS class.

Under the Medium General Service schedules the Company is proposing to set the summer and winter demand rates for the Primary and Secondary all-electric rate schedules to the demand rates for the general Primary and Secondary MGS schedule. Also, the Company is proposing to set the separately metered space heat rate equal to the third rate block of the Secondary MGS All-Electric rate block.

Finally, for the Large General Service rate class the Company is proposing to set the separately metered space heat rate equal to the third rate block of the LGS all-electric rate class.

Q. DO YOU AGREE WITH THE COMPANY'S VOLUMETRIC RATE DESIGN PROPOSAL FOR THE RESIDENTIAL CLASS?

A. No. I do not agree with the Company's proposal with the exception of the Residential Other Use rate schedule. The Company has made a number of adjustments particularly to the winter rate block structures for the Residential class. It was only in the Company's last rate case that the off-peak winter rate schedules were providing less than their cost of service. The Commission ordered that certain rates blocks within the class should be increased by an additional five percent; specifically the first rate block of the

Residential All-electric-one meter class and the space heating rate block of the Residential All-Electric-two meter class.[54]

In the instant case, the Company is proposing to decrease some of the very rates that the Commission previously ordered to increase. Although, the CCOSS shows that the off-peak winter rate schedules are providing a higher return than the on-peak summer rate schedules, decreasing the rates at this time may have unintended results. Therefore, I recommend to increase each of the volumetric rate blocks on an equal percentage basis and revaluate this matter in the next rate case when additional data is available

Q HAVE YOU PREPARED A SCHEDULE SUMMARIZING YOUR VOLUMETRIC RATE DESIGN RECOMMENDATIONS?

A. Yes. The results of my volumetric recommendations are shown in Schedule DED-14 and are based upon the Company's currently-proposed revenue requirement for illustrative purposes. In summary, I recommend that: (a) the first volumetric rate block be set at a summer energy rate of $0.14272/kWh and a winter energy rate of $0.12830/kWh; (b) in the second volumetric rate block the energy rate should be set at $0.14272/kWh and $0.07692/kWh for summer and winter, respectively; and (c) the third rate block be set at a summer energy rate of $0.14272/kWh and a winter energy rate of $0.06427/kWh. If the Commission decides to use Public Counsel's proposed revenue requirement, my volumetric rate recommendations would change to: (a) setting a first volumetric rate block summer energy rate of $0.12529/kWh and a winter energy rate of $0.11263/kWh; (b)

[54] In the Matter of the Kansas City Light & Power Company Request for Authority to implement a General Rate Increase for Electric Service, Case No. ER-2012-0174, Report and Order, Issued January 9, 2013 p 39.

setting the second volumetric rate block at an energy rate of $0.12529/kWh and $0.06752/kWh for summer and winter, respectively and (c) setting a third rate block results at a summer rate of $0.12529/kWh and a winter rate of $0.05642/kWh.

Q. WHAT ARE THE REMAINDER OF YOUR VOLUMETRIC RECOMMENDATIONS?

A. As I noted earlier, I agree with the Company that some volumetric rate elements could be realigned to better reflect the outcomes provided by the Company's CCOSS results. However, I disagree with the Company on several important residential rate design changes, particularly those associated with the dramatic changes in customer charges as I discussed in greater detail earlier.

I recommend that any revenue responsibilities not recovered through existing customer charge revenues be recovered through the volumetric rates. For those classes that have a Demand Charge and a Delivery Service Rate, I retain the existing relationship between the demand charge and the delivery rate and recommend allocating the increase on an equal percentage basis between the two components. My recommended revenue distribution and alternative rates based upon my alternative CCOSS and the Company's revenue increase are provided in Schedules DED-6 and DED-14. I have also provided a recommended revenue distribution in Schedule DED-7 that utilize the revenue requirement produced by the adjustments offered by OPC and Staff.

E. RATE DESIGN RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My electric rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated using a two-step methodology. In the first step, the under-earning classes receive an increase equal the system average increase. In the second step, any remaining revenue deficiency is allocated to the other rate classes in relation to their current test year revenues.
- Existing customer charges should not be increased in this proceeding.
- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.
- The Residential Other Use rates should be set to the mid-point of the Residential and SGS rates as proposed by the Company.
- The second and third winter rate blocks for the SGS All-Electric rate schedules should be set to the second and third winter rate blocks of the SGS general use schedule consistent with the results of the CCOSS and the Company's proposal.

V. SUMMARY OF RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS ON THE CLASS COST OF SERVICE STUDY.

A. I agree with the use of the Company's CCOSS and recommend that the Commission accept this model, its assumptions, and results as a starting point for setting rates in this proceeding. I have also provided, simply for reference purposes, the results of an alternative CCOSS that utilizes an Average and Excess Demand allocator, where demand is measured using non-coincident peak information (hereafter referred to generally as an "AED-NCP" allocator). The Commission has utilized and approved the AED-NCP allocator in past Ameren Missouri rate cases and I have presented the results for comparison purposes in Schedule DED-3.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My electric rate design recommendations can be summarized as follows:

- The revenue increase should be distributed to the customer classes on an across the board basis at the system average increase.
- Existing customer charges should not be increased in this proceeding.
- Distribution rates should be increased according to the results of my proposed CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis.
- The Residential Other Use rates should be set to the mid-point of the Residential and SGS rates as proposed by the Company.
- The second and third winter rate blocks for the SGS All-Electric rate schedules should be set to the second and third winter rate blocks of the SGS general use schedule consistent with the results of the CCOSS and the Company's proposal.

Q. DOES THIS COMPLETE YOUR TESTIMONY PREFILED ON APRIL 16, 2015?

A. Yes, it does.

DAVID E. DISMUKES, PH.D.

Professor, Executive Director &
Director of Policy Analysis
Center for Energy Studies
Louisiana State University
Baton Rouge, LA 70803-0301
Phone: (225) 578-4343
dismukes@lsu.edu

URL: www.enrg.lsu.edu

EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2014-Current	Executive Director
2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

School of the Coast and the Environment (Department of Environmental Studies)

2014-Current	Professor (Joint Appointment with CES)
2010-Current	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-1999	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

1. "An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity." (2012). With Mark J. Kaiser and Christopher J. Peters. *Exploration & Production: Oil and Gas Review.* 30(1): 18-22.

2. "The Value of Lost Production from the 2004-2005 Hurricane Seasons in the Gulf of Mexico." (2009). With Mark J. Kaiser and Yunke Yu. *Journal of Business Valuation and Economic Loss Analysis.* 4(2).

3. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

4. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

5. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review.* 10 (October): 206-212.

6. "Reflections on the U.S. Electric Power Production Industry: Precedent Decisions Vs. Market Pressures." (2003). With Robert F. Cope III and John W. Yeargain. *Journal of Legal, Ethical, and Regulatory Issues*. Volume 6, Number 1.

7. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest.* 38: 2.

8. "A Comment on the Integration of Price Cap and Yardstick Competition Schemes in Electrical Distribution Regulation." (2001). With Steven A. Ostrover. *IEEE Transactions on Power Systems.* 16 (4): 940 -942.

9. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

10. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

11. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics.* 21:153-166.

12. "Capacity and Economies of Scale in Electric Power Transmission" (1999). With Robert F. Cope and Dmitry Mesyanzhinov. *Utilities Policy* 7: 155-162.

13. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.

14. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal.* 63:1108-1112.

15. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

PUBLICATIONS: PEER REVIEWED PROCEEDINGS

1. "Economic and Policy Issues in Sustaining an Adequate Oil Spill Contingency Fund in the Aftermath of a Catastrophic Incident." (2014). With Stephen R. Barnes and Gregory B. Upton. *Proceedings of the Thirty-seventh AMOP Technical Seminar on Environmental contamination and Response.* June: 506-524.

2. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues.* September: 17-21.

3. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management.* March.

4. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.

5. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering.* June: 294-298.

6. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development.* October: 499-504.

7. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

8. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings.* U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) *Proceedings of the 51st Mineral Law Institute*, Louisiana State University, Baton Rouge, LA. April 2, 2004.

3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers.* December 2003.

4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All.* October.

5. "A New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities." (2002). With Vicki Zatarain. *Proceedings of the 2002 National IMPLAN Users Conference*: 241-258.

6. "Analysis of the Economic Impact Associated with Oil and Gas Activities on State Leases." (2002). With Dmitry Mesyanzhinov, Robert H. Baumann, and Allan G. Pulsipher. *Proceedings of the 2002 National IMPLAN Users Conference*: 149-155.

7. "Do Deepwater Activities Create Different Impacts to Communities Surrounding the Gulf OCS?" (2001). *Proceedings of the International Association for Energy Economics: 2001: An Energy Odyssey?* April.

8. "Modeling the Economic Impact of Offshore Activities on Onshore Communities." (2000). With Williams O. Olatubi. *Proceedings of the 20th Annual Information Transfer Meeting.* U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

9. "Empirical Challenges in Estimating the Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico" (2000). With Williams O. Olatubi. *Proceedings of the International Association for Energy Economics: Transforming Energy Markets.* August.

10. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: The Only Constant is Change* August: 444-452.

11. "Modeling Electric Power Markets in a Restructured Environment" (1998). With Robert F. Cope and Dan Rinks. *Proceedings of the International Association for Energy Economics: Technology's Critical Role in Energy and Environmental Markets.* October: 48-56.

12. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Bob Baumann, and Dmitry Mesyanzhinov. *Proceedings of the 16th Annual Information Transfer Meeting.* U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana: 162-166.

13. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the 15th Annual Information Transfer Meeting.* U.S. Department of Interior, Minerals Management Service: New Orleans, Louisiana.

PUBLICATIONS: BOOK CHAPTERS

1. "The Role of Distributed Energy Resources in a Restructured Power Industry." (2006). In *Electric Choices: Deregulation and the Future of Electric Power.* Edited by Andrew N. Kleit. Oakland, CA: The Independent Institute (Rowman & Littlefield Publishers, Inc.), 181-208.

2. "The Road Ahead: The Outlook for Louisiana Energy." (2006). In *Commemorating Louisiana Energy: 100 Years of Louisiana Natural Gas Development.* Houston, TX: Harts Energy Publications, 68-72.

3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the*

Issues. With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.

4. "Alaskan North Slope Natural Gas Development." (2003). In *Natural Gas and Electric Industries Analysis 2003.* With William E. Nebesky, Dmitry Mesyanzhinov, and Jeffrey M. Burke. Edited by Robert Willett. Houston, TX: Financial Communications Company, 185-205.

5. "Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry." (2002). In *Natural Gas and Electric Industries Analysis 2001-2002.* Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

6. "The Hydropower Industry of the United States." (2000). With Dmitry Mesyanzhinov. In *Renewable Energy: Trends and Prospects.* Edited by E.W. Miller and A.I. Panah. Lafayette, PN: The Pennsylvania Academy of Science, 133-146.

7. "Electric Power Generation." (2000). In the *Macmillan Encyclopedia of Energy.* Edited by John Zumerchik. New York: Macmillan Reference.

PUBLICATIONS: BOOK REVIEWS

1. Review of ***Renewable Resources for Electric Power: Prospects and Challenges.*** Raphael Edinger and Sanjay Kaul. (Westport, Connecticut: Quorum Books, 2000), pp 154. ISBN 1-56720-233-0. *Natural Resources Forum. (2000).*

2. Review of ***Electricity Transmission Pricing and Technology***, edited by Michael Einhorn and Riaz Siddiqi. (Boston: Kluwer Academic Publishers, 1996) pp. 282. ISBN 0-7923-9643-X. *Energy Journal* 18 (1997): 146-148.

3. Review of ***Electric Cooperatives on the Threshold of a New Era*** by Public Utilities Reports. (Vienna, Virginia: Public Utilities Reports, 1996) pp. 232. ISBN 0-910325-63-4. *Energy Journal* 17 (1996): 161-62.

PUBLICATIONS: TRADE AND PROFESSIONAL JOURNALS

1. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine.* Vol. 30: No. 2, p. 76 (March).

2. "Louisiana's Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials" (2012). *Spectrum.* January-April: 18-20.

3. "The Impact of Legacy Lawsuits on Louisiana's Conventional Drilling Activity" (2012). *LOGA Industry Report.* Spring 2012: 27-34.

4. "An Empirical Analysis of Differences in Interstate Oil and Natural Gas Drilling Activity," (2012). With Mark J. Kaiser and Christopher Peters. *Exploration & Production: Oil and Gas Review.* Vol. 10, Issue 1: (1-6).

5. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal.* Vol. 106.27: 32-26 (July 21) (part 3 of 3).

6. "Model Framework Can Aid Decision on Redevelopment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal.* Vol. 106.26: 49-53 (July 14) (part 2 of 3).

7. "Field Redevelopment Economics and Storm Impact Assessment." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal.* Vol. 106.25: 42-50 (July 7) (part 1 of 3).

8. "The IRS' Latest Proposal on Tax Normalization: A Pyrrhic Victory for Ratepayers," (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 55(1): 217-236

9. "Executive Compensation in the Electric Power Industry: Is It Excessive?" (2006). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 54(4): 913-940.

10. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 54(3): 693-706.

11. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy? (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 54 (2): 401-424

12. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 54(1): 211-223

13. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 53 (4): 981-997

14. "Can LNG Preserve the Gas-Power Convergence?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 53 (3):783-796.

15. "Competitive Bidding as a Means of Securing Opportunities for Efficiency." (2004). With Elizabeth A. Downer. *Electricity and Natural Gas* 21 (4): 15-21.

16. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 53(2): 479-494.

17. "The Challenges Associated with a Nuclear Power Revival: Its Past." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 53 (1): 193-211.

18. "Deregulation of Generating Assets and The Disposition of Excess Deferred Federal Income Taxes: A 'Catch-22' for Ratepayers." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 873-891.

19. "Will Competitive Bidding Make a Comeback?" (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 659-674

20. "An Electric Utility's Exposure to Future Environmental Costs: Does It Matter? You Bet!" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 457-469.

21. "White Paper or White Flag: Do FERC's Concessions Represent A Withdrawal from Wholesale Power Market Reform?" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 52: 197-207.

22. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 823-848.

23. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue.* 11: 20-24.

24. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 635-652.

25. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 433-454.

26. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal.* 19: 10-15.

27. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 51: 207-225.

28. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter.* Second Quarter: 16-20.

29. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50: 943-960.

30. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

31. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly.* 50:531-543.

32. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 50:235-249.

33. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 49:947-973.

34. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II.

Oil, Gas and Energy Quarterly. 49: 743-759.

35. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal.* January: 9-16.

36. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* December: 529-540.

37. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* September: 211-224.

38. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 49: 751-765.

39. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter.* 49: 78-82.

40. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly.* 48:593-602.

41. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.

42. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

43. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

44. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly.* February 1: 30-33.

45. "Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

PUBLICATIONS: REPORTS AND OTHER MANUSCRIPTS

1. *Unconventional Resources and Louisiana's Manufacturing Development Renaissance* (2013). Baton Rouge, LA: LSU Center for Energy Studies, 93 pp.

2. *Removing Big Wind's "Training Wheels:" The Case for Ending the Production Tax Credit* (2012). Washington, DC: American Energy Alliance, 19 pp.

3. *The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana.* (2012). Baton Rouge, LA: LSU Center for Energy Studies, 62 pp.

4. *Diversifying Energy Industry Risk in the GOM: Post-2004 Changes in Offshore Oil and Gas*

Insurance Markets. (2011) With Christopher P. Peters. U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-054. 95pp.

5. *OCS-Related Infrastructure Fact Book. Volume I: Post-Hurricane Impact Assessment.* (2011). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2011-043. 372 pp.

6. *Fact Book: Offshore Oil and Gas Industry Support Sectors.* (2010). U.S. Department of the Interior, Bureau of Ocean Energy Management, Gulf of Mexico Region, New Orleans, LA. OCS Study BOEM 2010-042. 138pp.

7. *The Impacts of Greenhouse Gas Regulation on the Louisiana Economy.* (2011). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 3 and 4 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 134 pp.

8. *Overview of States' Climate Action and/or Alternative Energy Policy Measures.* (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, and Lauren L. Stuart. Louisiana Greenhouse Gas Inventory Project, Task 2 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 30 pp.

9. *Louisiana Greenhouse Gas Inventory.* (2010). With Michael D. McDaniel, Christopher Peters, Kathryn R. Perry, Lauren L. Stuart, and Jordan L. Gilmore. Louisiana Greenhouse Gas Inventory Project, Task 1 Report. Prepared for the Louisiana Department of Economic Development. Baton Rouge, LA: LSU Center for Energy Studies, 114 pp.

10. *The Benefits of Continued and Expanded Investments in the Port of Venice.* (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

11. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico.* (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

12. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal.* (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

13. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project.* (2007). Report Prepared on Behalf of Leucadia Corporation.

14. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard.* (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

15. *The Importance of Energy Production and Infrastructure in Plaquemines Parish.* (2006).

Report Prepared on Behalf of Project Rebuild Plaquemines.

16. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity.* (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

17. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study.* (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

18. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana.* (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

19. *Economic Opportunities for LNG Development in Louisiana.* (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

20. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production.* (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

21. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

22. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

23. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

24. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases.* (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

25. *Alaska In-State Natural Gas Demand Study.* (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

26. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana.* (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi.

Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

27. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

28. *Energy Conservation and Electric Restructuring In Louisiana.* (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

29. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

30. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator.* "Analysis of the Potential for Combined Heat and Power (CHP) in Louisiana. (2013). Louisiana Department of Natural Resources. Total Project: $90,000. Status: In Progress.

2. *Co-Principal Investigator.* "CNH: A Tale of Two Louisianas: Coupled Natural-Human Dynamics in a Vulnerable Coastal System" (2013) With Nina Lam, Margaret Reams, Kam-Biu Liu, Victor Rivera, and Kelley Pace. National Science Foundation. Total Project: $1.5 million. Status: In Progress (Sept 2012-Feb 2017).

3. *Principal Investigator.* "Examination of Unconventional Natural Gas and Industrial Economic Development" (2012). America's Natural Gas Alliance. Total Project: $48,210. Status: Completed.

4. *Principal Investigator.* "Investigation of the Potential Economic Impacts Associated with Shell's Proposed Gas-To-Liquids Project" (2012). Shell Oil Company, North America. Total Project: $76,708. Status: Completed.

5. *Principal Investigator.* "Analysis of the Federal Wind Energy Production Tax Credit." American Energy Alliance. Total Project: $20,000. Status: Completed.

6. *Principal Investigator.* "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: Open. Status: Completed.

7. *Principal Investigator.* "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

8. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $150,000. Status: Completed.

9. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

10. *Principal Investigator.* "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

11. *Principal Investigator.* "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

12. *Principal Investigator.* "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

13. *Principal Investigator.* "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

14. *Principal Investigator.* "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

15. *Principal Investigator.* "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

16. *Principal Investigator.* "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

17. *Principal Investigator.* "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

18. *Principal Investigator.* "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of

Mineral Resources. Total Project Funding: $75,000. Status: Completed.

19. *Principal Investigator.* " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

20. *Principal Investigator.* "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

21. *Principal Investigator.* "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

22. *Principal Investigator.* "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

23. *Principal Investigator.* "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

24. *Co-Principal Investigator.* "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

25. *Principal Investigator.* "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

26. *Principal Investigator.* "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

27. *Principal Investigator.* "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

28. *Principal Investigator.* "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding:

$19,948. Status: Completed.

29. *Co-Principal Investigator.* "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17, 2012.

2. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7, 2009.

3. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

5. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

6. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

7. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

8. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

9. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

10. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and

Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

11. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

12. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

13. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

14. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

15. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

16. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

17. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

18. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

19. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

20. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

21. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

22. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

23. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

24. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

25. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

26. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

27. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

28. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

29. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

30. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

31. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

32. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

33. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

34. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

35. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

36. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

37. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

38. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

41. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

42. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

43. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

44. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.

2. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

3. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

4. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

5. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

6. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

7. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

8. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

9. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

10. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

2. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

3. "Industry Investments and the Economic Development of Unconventional Development." Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

4. "Globalization of Energy Prices and Supply." Federal Reserve Band of Atlanta Energy Advisory Council, Atlanta, Georgia. March 25.

5. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

6. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of Statue Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

7. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

8. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

9. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013). National Association of Statue Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

10. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

11. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

12. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

13. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of Statue Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

14. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

15. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

16. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

17. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities

State Government Organization Conference, Pointe Clear, Alabama. July 9.

18. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

19. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Allianace Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

20. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

21. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

22. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

23. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

24. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

25. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

26. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

27. "Trends, Issues, and Market Changes for Crude Oil and Natural Gas." (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

28. "Game Changers in Crude and Natural Gas Markets." (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

29. "The Outlook for Renewables in a Changing Power and Natural Gas Market." (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

30. "The Changing Dynamics of Crude and Natural Gas Markets." (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

31. "The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale." (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

32. "The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency." (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

33. "Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

34. "Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?" (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

35. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

36. "The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana." (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

37. "Louisiana's Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

38. "EPA's Recently Proposed Cross State Air Pollution Rule ("CSAPR") and Its Impacts on Louisiana." (2011). Bossier Chamber of Commerce. November 18, 2011.

39. "Facilitating the Growth of America's Natural Gas Advantage." (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

40. "CSAPR and EPA Regulations Impacting Louisiana Power Generation." (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

41. "Natural Gas Trends and Impact on Industrial Development." (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

42. "Energy Market Changes and Policy Challenges." (2011). Southeast Manpower Tripartite Alliance ("SEMTA") Summer Conference. Nashville, TN September 2, 2011.

43. "EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers." (2011). Workshop: "A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

44. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

45. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

46. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

47. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

48. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

49. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

50. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

51. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

52. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

53. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

54. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

55. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

56. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

57. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

58. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

59. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

60. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

61. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

62. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

63. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

64. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

65. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

66. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

67. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

68. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

69. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

70. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

71. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

72. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

73. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

74. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

75. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

76. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

77. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

78. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

79. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

80. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

81. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

82. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

83. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

84. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

85. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

86. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

87. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

88. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

89. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

90. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

91. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

92. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

93. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

94. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

95. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

96. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

97. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

98. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

99. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

100. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

101. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

102. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

103. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

104. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

105. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

106. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

107. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

108. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

109. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

110. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

111. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

112. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

113. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

114. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

115. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

116. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

117. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

118. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

119. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

120. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

121. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

122. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

123. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

124. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

125. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

126. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

127. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

128. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

129. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

130. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

131. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

132. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

133. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

134. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

135. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

136. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

137. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

138. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

139. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

140. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

141. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

142. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

143. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

144. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

145. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

146. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

147. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

148. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

149. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

150. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

151. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

152. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

153. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

154. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

155. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

156. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

157. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

158. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

159. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

160. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

161. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

162. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

163. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

164. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

165. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

166. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

167. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

168. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

169. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

170. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

171. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

172. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

173. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

174. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

175. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

176. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

177. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

178. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

179. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

180. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

181. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

182. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

183. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

184. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

185. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

186. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

187. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

188. Roundtable Moderator, “Stakeholder Perspectives on Electric Utility Stranded Costs.” Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

189. Panelist, “Deregulation and Competition.” American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area. On behalf of the Missouri Office of the People's Counsel. Issues: rate design, revenue distribution, class cost of service

2. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

3. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

4. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

5. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

6. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of

Public Utilities. Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

7. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015.On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

8. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service Commission. In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

9. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. Anthony Williams, et al., v. Duke energy International, Inc., et al. On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

10. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

11. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated). On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

12. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

13. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and

220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

14. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

15. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

16. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

17. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

18. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

19. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

20. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

21. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

22. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

23. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

24. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

25. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

26. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. In Re: Potomac Electric Power Company ("Pepco") General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

27. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. In Re: the Delmarva Power and Light Company General Rate Case. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

28. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities. On the

Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

29. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

30. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization Adjustments, Class Cost of Service Study, Rate Design.

31. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

32. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

33. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

34. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

35. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. On the Behalf of the Maryland Office of People's Counsel. In the Matter of

the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

36. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

37. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

38. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Capital Cost Rider, Revenue Decoupling.

39. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: Pipeline Replacement Rider, Revenue Decoupling.

40. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

41. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

42. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

43. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

44. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

45. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

46. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

47. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

48. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

49. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

50. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and

Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

51. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

52. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

53. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

54. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

55. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

56. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

57. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

58. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

59. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

60. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

61. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

62. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

63. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

64. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

65. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and

August 20, 2008.

66. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

67. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

68. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

69. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

70. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

71. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

72. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

73. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

74. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

75. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

76. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

77. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

78. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

79. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

80. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

81. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

82. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of

State Drilling.

83. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

84. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

85. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

86. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

87. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

88. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

89. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

90. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

91. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

92. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge,

State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

93. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

94. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

95. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

96. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

97. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

98. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

99. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

100. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

101. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine

Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

102. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

103. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

104. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

105. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

106. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

107. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

108. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

109. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

110. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

111. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

112. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

113. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

114. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

115. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Editorial Board Member, 2015-Current, *Utilities Policy*
Referee, 2014-Current, *Utilities Policy*
Referee, 2010-Current, *Economics of Energy & Environmental Policy*
Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE") and the National Association for Business Economics ("NABE").

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)
Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

THESIS/DISSERTATIONS COMMITTEES

Active:
2 Thesis Committee Memberships (Environmental Studies)
1 Ph.D. Dissertation Committee (Economics)

Completed:
6 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Schedules

Alternative CCOSS AED-NCP

	Missouri Retail	Residential	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Large Power Service	Total Lighting
SUMMARY OF OPERATING INCOME & RATE BASE							
OPERATING REVENUE							
Retail Sales revenue	$ 767,355,793	$ 285,159,916	$ 48,836,426	$ 103,290,211	$ 180,113,158	$ 140,231,588	$ 9,724,494
Other Operating Income	$ 413,609,396	$ 125,816,485	$ 19,875,860	$ 53,443,371	$ 107,177,808	$ 103,137,667	$ 4,158,205
TOTAL OPERATING REVENUE	$ 1,180,965,189	$ 410,976,402	$ 68,712,286	$ 156,733,582	$ 287,290,966	$ 243,369,255	$ 13,882,699
OPERATING EXPENSES							
Fuel	$ 222,511,027	$ 67,745,516	$ 10,665,367	$ 28,753,251	$ 57,593,198	$ 55,515,719	$ 2,237,976
Purchased Power	$ 304,735,754	$ 92,266,295	$ 14,608,136	$ 39,377,911	$ 79,157,649	$ 76,274,910	$ 3,050,853
Other Operation & Maintenance Expense	$ 303,491,601	$ 140,108,184	$ 18,065,077	$ 35,179,279	$ 57,592,565	$ 47,867,084	$ 4,679,413
Depreciation expenses (After Clearings)	$ 116,953,542	$ 52,315,749	$ 6,683,684	$ 15,021,699	$ 23,444,648	$ 17,816,032	$ 1,671,531
Amortization Expenses	$ 15,665,901	$ 6,880,929	$ 875,633	$ 1,997,536	$ 3,223,008	$ 2,461,551	$ 227,245
Taxes Other Than Income Taxes	$ 58,619,563	$ 26,127,914	$ 3,334,432	$ 7,356,645	$ 11,847,864	$ 9,095,876	$ 856,831
Current Income Taxes	$ 14,819,681	$ (9,357,190)	$ 3,071,043	$ 5,360,229	$ 10,848,498	$ 5,017,573	$ (120,473)
Deferred Income Taxes	$ 15,669,609	$ 6,988,357	$ 889,527	$ 1,981,499	$ 3,171,356	$ 2,411,924	$ 226,947
TOTAL ELECTRIC OPERATING EXPENSES	$ 1,052,466,678	$ 383,075,754	$ 58,192,898	$ 135,028,250	$ 246,878,786	$ 216,460,669	$ 12,830,322
NET ELECTRIC OPERATING INCOME	$ 128,498,510	$ 27,900,648	$ 10,519,388	$ 21,705,332	$ 40,412,180	$ 26,908,585	$ 1,052,377
RATE BASE							
Total Electric Plant	$ 5,043,175,544	$ 2,241,465,141	$ 284,699,412	$ 636,960,243	$ 1,024,994,522	$ 782,595,955	$ 72,460,270
Less: Accum. Prov. For Depreciation	$ 2,040,172,942	$ 909,799,682	$ 116,656,400	$ 253,605,945	$ 410,495,448	$ 314,346,286	$ 35,269,180
NET PLANT	$ 3,003,002,603	$ 1,331,665,459	$ 168,043,012	$ 383,354,297	$ 614,499,074	$ 468,249,669	$ 37,191,091
PLUS:							
Cash Working Capital	$ (58,530,428)	$ (24,625,252)	$ (3,504,482)	$ (7,582,638)	$ (12,502,446)	$ (9,516,620)	$ (798,990)
Materials & Supplies	$ 57,386,822	$ 24,450,942	$ 3,057,074	$ 7,259,379	$ 12,224,772	$ 9,613,709	$ 780,946
Prepayments	$ 6,397,922	$ 2,784,139	$ 342,239	$ 784,655	$ 1,339,448	$ 1,065,580	$ 81,861
Fuel Inventory	$ 80,107,604	$ 24,200,924	$ 3,835,784	$ 10,358,639	$ 20,800,550	$ 20,110,413	$ 801,295
Regulatory Assets	$ 111,292,579	$ 46,707,104	$ 7,435,109	$ 13,350,767	$ 23,379,895	$ 18,996,010	$ 1,423,695
LESS:							
Customer Advances For Construction	$ 167,781	$ 91,553	$ 12,598	$ 22,671	$ 24,733	$ 12,753	$ 3,474
Customer Deposits	$ 3,567,416	$ 1,780,441	$ 1,424,044	$ 301,429	$ 56,982	$ 4,521	$ -
Deferred Income Taxes	$ 599,672,820	$ 266,527,649	$ 33,852,976	$ 75,739,530	$ 121,879,826	$ 93,056,750	$ 8,616,090
Deferred Gain on SO2 Emissions Allowance	$ 39,136,133	$ 11,833,473	$ 1,875,216	$ 5,058,000	$ 10,170,874	$ 9,807,708	$ 390,863
Deferred Gain (Loss) Emissions Allowance	$ 23,191	$ 7,012	$ 1,111	$ 2,997	$ 6,027	$ 5,812	$ 232
TOTAL RATE BASE	$ 2,557,089,761	$ 1,124,943,188	$ 142,042,791	$ 326,400,473	$ 527,602,852	$ 405,631,219	$ 30,469,239
RATE OF RETURN	5.03%	2.48%	7.41%	6.65%	7.66%	6.63%	3.45%
RELATIVE RATE OF RETURN	1.00	0.49	1.47	1.32	1.52	1.32	0.69

Source: Company CCOSS.

Comparison of Class Rates of Return Under Company and Alternative Cost of Service Study

	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting
Company CCOSS - AP- 4CP						
Return	3.71%	7.14%	6.33%	6.61%	4.16%	12.20%
Relative ROR	0.74	1.42	1.26	1.32	0.83	2.43
Alternative CCOSS - AED-NCP						
Return	2.48%	7.41%	6.65%	7.66%	6.63%	3.45%
Relative ROR	0.49	1.47	1.32	1.52	1.32	0.69

Source: Company CCOSS Summary Results, Schedule TMR-7; Schedule DED-1.

Results of Company CCOSS

	Missouri Retail	Residential	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Large Power Service	Total Lighting
SUMMARY OF OPERATING INCOME & RATE BASE							
OPERATING REVENUE							
Retail Sales Revenue	$ 767,355,793	$ 285,159,916	$ 48,836,426	$ 103,290,211	$ 180,113,158	$ 140,231,588	$ 9,724,494
Other Operating Revenue	$ 413,609,396	$ 125,694,904	$ 19,878,505	$ 53,451,055	$ 107,218,025	$ 103,223,236	$ 4,143,671
TOTAL OPERATING REVENUE	$ 1,180,965,189	$ 410,854,821	$ 68,714,931	$ 156,741,266	$ 287,331,183	$ 243,454,824	$ 13,868,164
OPERATING EXPENSES							
Fuel	$ 222,511,027	$ 67,464,123	$ 10,671,489	$ 28,771,035	$ 57,686,279	$ 55,713,765	$ 2,204,337
Purchased Power	$ 304,735,754	$ 92,266,295	$ 14,608,136	$ 39,377,911	$ 79,157,649	$ 78,274,910	$ 3,050,853
Other Operation & Maintenance Expenses	$ 303,491,601	$ 130,026,972	$ 18,284,387	$ 35,816,395	$ 60,927,309	$ 54,962,276	$ 3,474,261
Depreciation Expenses (After Clearings)	$ 116,953,542	$ 47,708,475	$ 6,783,912	$ 15,313,071	$ 24,968,679	$ 21,058,648	$ 1,120,757
Amortization Expenses	$ 15,665,901	$ 6,229,066	$ 889,814	$ 2,038,733	$ 3,438,636	$ 2,920,334	$ 149,319
Taxes Other Than Income Taxes	$ 58,619,563	$ 23,770,517	$ 3,385,716	$ 7,505,629	$ 12,627,663	$ 10,755,021	$ 575,017
Current Income Taxes	$ 14,819,681	$ (964,231)	$ 2,888,460	$ 4,829,807	$ 8,072,208	$ (889,421)	$ 882,857
Deferred Income Taxes	$ 15,669,609	$ 6,370,252	$ 902,973	$ 2,020,562	$ 3,375,818	$ 2,846,949	$ 153,056
TOTAL ELECTRIC OPERATING EXPENSES	$ 1,052,466,678	$ 372,871,468	$ 58,414,886	$ 135,673,145	$ 250,254,241	$ 223,642,482	$ 11,610,457
NET ELECTRIC OPERATING INCOME	$ 128,498,510	$ 37,983,352	$ 10,300,046	$ 21,068,121	$ 37,076,943	$ 19,812,342	$ 2,257,707
RATE BASE							
Total Electric Plant	$ 5,043,175,544	$ 2,037,927,641	$ 289,127,240	$ 649,823,489	$ 1,092,322,280	$ 925,846,375	$ 48,128,519
Less: Accum. Prov. For Depreciation	$ 2,040,172,942	$ 825,807,274	$ 118,483,601	$ 258,914,132	$ 438,279,127	$ 373,460,443	$ 25,228,365
NET PLANT	$ 3,003,002,603	$ 1,212,120,367	$ 170,643,639	$ 390,909,357	$ 654,043,153	$ 552,385,932	$ 22,900,155
PLUS:							
Cash Working Capital	$ (58,530,428)	$ (23,131,624)	$ (3,536,975)	$ (7,677,033)	$ (12,996,521)	$ (10,567,841)	$ (620,435)
Materials & Supplies	$ 57,386,822	$ 21,630,951	$ 3,118,421	$ 7,437,598	$ 13,157,591	$ 11,598,429	$ 443,832
Prepayments	$ 6,397,922	$ 2,460,858	$ 349,271	$ 805,085	$ 1,446,386	$ 1,293,107	$ 43,215
Fuel Inventory	$ 80,107,604	$ 24,200,924	$ 3,835,784	$ 10,358,639	$ 20,800,550	$ 20,110,413	$ 801,295
Regulatory Assets	$ 111,292,579	$ 43,575,623	$ 7,503,232	$ 13,548,672	$ 24,415,751	$ 21,199,957	$ 1,049,344
LESS:							
Customer Advances For Construction	$ 167,781	$ 91,553	$ 12,598	$ 22,671	$ 24,733	$ 12,753	$ 3,474
Customer Deposits	$ 3,567,416	$ 1,780,441	$ 1,424,044	$ 301,429	$ 56,982	$ 4,521	$ -
Deferred Income Taxes	$ 599,672,820	$ 242,325,456	$ 34,379,479	$ 77,269,070	$ 129,885,620	$ 110,090,339	$ 5,722,856
Deferred Gain on SO2 Emissions Allowance	$ 39,136,133	$ 11,833,473	$ 1,875,216	$ 5,058,000	$ 10,170,874	$ 9,807,708	$ 390,863
Deferred Gain (Loss) Emissions Allowance	$ 23,191	$ 7,012	$ 1,111	$ 2,997	$ 6,027	$ 5,812	$ 232
TOTAL RATE BASE	$ 2,557,089,761	$ 1,024,819,164	$ 144,220,924	$ 332,728,152	$ 560,722,675	$ 476,098,864	$ 18,499,982
RATE OF RETURN	5.03%	3.71%	7.14%	6.33%	6.61%	4.16%	12.20%
RELATIVE RATE OF RETURN	1.00	0.74	1.42	1.26	1.32	0.83	2.43

Source: Company CCOSS Summary Results, Schedule TMR-7.

Comparison of Company Class Rate of Returns Under Current and Proposed Rates

	Total Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting
Current							
Return	5.03%	3.71%	7.14%	6.33%	6.61%	4.16%	12.20%
Relative ROR	1.00	0.74	1.42	1.26	1.32	0.83	2.43
Proposed							
Return	7.94%	6.41%	10.43%	9.35%	9.73%	7.02%	17.31%
Relative ROR	1.00	0.81	1.31	1.18	1.23	0.88	2.18

Source: Company CCOSS Summary Results, Schedule TMR-7; Company Workpaper, KCPL-MO Revenue Summary.

Comparison of Past and Present Class Rate of Returns

	Total Missouri Retail	Residential	Small General Service	Medium General Service	Large General Service	Large Power Service	Lighting
Case ER-2012-0174							
Return	5.54%	5.43%	10.97%	7.09%	5.80%	3.01%	6.19%
Relative ROR	1.00	0.98	1.98	1.28	1.05	0.54	1.12
Current							
Return	5.03%	3.71%	7.14%	6.33%	6.61%	4.16%	12.20%
Relative ROR	1.00	0.74	1.42	1.26	1.32	0.83	2.43

Source: Company CCOSS Summary Results, Schedule TMR-7; Company Response to OPC DR 60.

Recommended Revenue Distribution at Company Proposed Revenue Requirement

		Residential				Small General Service				Medium General Service			
		Regular	Time of Day	All Electric	Separately Metered	Regular	Unmetered	All Electric	Separately Metered	Primary	Secondary	All Electric	Separately Metered
Cost of Service Results													
Operating Income	$ 128,498,510	$ 29,036,340	$ 8,016	$ 7,320,279	$ 1,618,718	$ 9,625,170	$ 206,663	$ 336,022	$ 132,191	$ 194,337	$ 18,837,597	$ 1,669,770	$ 366,418
Rate Base	$ 2,557,069,761	$ 766,744,775	$ 217,191	$ 201,268,245	$ 56,568,952	$ 135,077,974	$ 2,378,997	$ 4,864,919	$ 1,899,035	$ 2,340,916	$ 292,380,477	$ 31,630,733	$ 6,376,026
ROR	5.03%	3.79%	3.69%	3.64%	2.86%	7.13%	8.69%	6.91%	6.96%	8.30%	6.44%	5.28%	5.75%
Relative Rate of Return	1.00	0.75	0.73	0.72	0.57	1.42	1.73	1.37	1.39	1.65	1.28	1.05	1.14
Revenue Requirement Results													
Operating Income	$ 128,498,510	$ 29,036,340	$ 8,016	$ 7,320,279	$ 1,618,718	$ 9,625,170	$ 206,663	$ 336,022	$ 132,191	$ 194,337	$ 18,837,597	$ 1,669,770	$ 366,418
Rate Base	$ 2,557,069,761	$ 766,744,775	$ 217,191	$ 201,268,245	$ 56,568,952	$ 135,077,974	$ 2,378,997	$ 4,864,919	$ 1,899,035	$ 2,340,916	$ 292,380,477	$ 31,630,733	$ 6,376,026
ROR	5.03%	3.79%	3.69%	3.64%	2.86%	7.13%	8.69%	6.91%	6.96%	8.30%	6.44%	5.28%	5.75%
Relative Rate of Return	1.00	0.75	0.73	0.72	0.57	1.42	1.73	1.37	1.39	1.65	1.28	1.05	1.14
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 120,894,547												
Operating Income Deficiency	$ 74,483,274												
ROR Schedule	5.03%												
Step One Increase													
System ROR	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%
Incremental Income	$ 74,483,274	$ 9,494,010	$ 2,898	$ 2,794,829	$ 1,223,977	$ (2,837,250)	$ (87,114)	$ (91,551)	$ (36,761)	$ (76,701)	$ (4,144,934)	$ (80,267)	$ (46,011)
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 120,894,547	$ 15,409,822	$ 4,704	$ 4,536,316	$ 1,986,649	$ (4,605,170)	$ (141,395)	$ (148,597)	$ (59,667)	$ (124,495)	$ (6,727,685)	$ (130,281)	$ (74,681)
Percent Increase @ System ROR	15.71%	7.19%	7.93%	8.13%	13.40%	-10.09%	-14.96%	-9.41%	-9.53%	-15.14%	-7.38%	-1.41%	-3.90%
Maximum Increase @ 1 Times System Average Increase	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%
Required Percentage Increase without Limitation	15.71%	7.19%	7.93%	8.13%	13.40%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Initial Increase	$ 67,141,772	$ 33,656,381	$ 9,322	$ 8,763,560	$ 2,329,831								
Shortfall in Required Increase	$ 53,752,775												
Step Two Increase													
Increase	$ 342,118,876	$ -	$ -	$ -	$ -	$ 45,638,828	$ 945,358	$ 1,579,169	$ 625,866	$ 822,432	$ 91,197,272	$ 9,260,995	$ 1,912,974
Allocation of Shortfall to Remaining Customer Classes	$ 53,752,775	$ -	$ -	$ -	$ -	$7,170,646.97	$ 148,537	$ 243,115	$ 98,334	$ 129,218	$ 14,328,664	$ 1,455,062	$ 300,561
Total Required Increase	$ 120,894,547	$ 33,656,381	$ 9,322	$ 8,763,560	$ 2,329,831	$ 7,170,647	$ 148,537	$ 243,115	$ 98,334	$ 129,218	$ 14,328,664	$ 1,455,062	$ 300,561
Proposed Revenue Allocation													
ROR	7.94%	6.49%	6.34%	6.32%	5.40%	10.40%	12.53%	10.05%	10.15%	11.70%	9.46%	8.11%	8.65%
Incremental Income	$ 74,483,274	$ 20,735,736	$ 5,743	$ 5,399,252	$ 1,435,412	$ 4,417,844	$ 91,514	$ 152,664	$ 60,584	$ 79,611	$ 8,827,907	$ 896,465	$ 185,176
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 120,894,547	$ 33,656,381	$ 9,322	$ 8,763,560	$ 2,329,831	$ 7,170,647	$ 148,537	$ 243,115	$ 98,334	$ 129,218	$ 14,328,664	$ 1,455,062	$ 300,561
Final Relative Rate of Return	1.00	0.82	0.80	0.80	0.68	1.31	1.58	1.27	1.28	1.47	1.19	1.02	1.09

Witness: Dismukes
ER-2014-0370
Schedule DED-6
Page 2 of 2

Recommended Revenue Distribution at Company Proposed Revenue Requirement

	Large General Service				Large Power Service				All Lighting
	Primary	Secondary	All Electric	Separately Metered	Primary	Secondary	Substation	Transmission	Lighting
Cost of Service Results									
Operating Income	$ 4,436,392	$ 20,589,253	$ 11,122,906	$ 928,391	$ 11,904,683	$ 5,037,549	$ 854,013	$ 2,016,097	$ 2,257,707
Rate Base	$ 58,651,685	$ 294,900,987	$ 194,999,832	$ 12,170,171	$ 248,076,520	$ 107,574,153	$ 68,807,989	$ 107,574,153	$ 18,499,952
ROR	7.56%	6.98%	5.70%	7.63%	4.80%	4.66%	1.24%	1.87%	12.20%
Relative Rate of Return	1.51	1.39	1.14	1.52	0.95	0.93	0.25	0.37	2.43
Revenue Requirement Results									
Operating Income	$ 4,436,392	$ 20,589,253	$ 11,122,906	$ 928,391	$ 11,904,683	$ 5,037,549	$ 854,013	$ 2,016,097	$ 2,257,707
Rate Base	$ 58,651,685	$ 294,900,987	$ 194,999,832	$ 12,170,171	$ 248,076,520	$ 107,574,153	$ 68,807,989	$ 107,574,153	$ 18,499,982
ROR	7.56%	6.98%	5.70%	7.63%	4.80%	4.68%	1.24%	1.87%	12.20%
Relative Rate of Return	1.51	1.39	1.14	1.52	0.95	0.93	0.25	0.37	2.43
Rate Schedule Specific Revenue Increase Allocation									
Revenue Requirement									
Operating Income Deficiency									
ROR Schedule									
Step One Increase									
System ROR	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%	5.03%
Incremental Income	$ (1,439,036)	$ (5,769,930)	$ (1,323,803)	$ (316,817)	$ 561,623	$ 368,252	$ 2,603,716	$ 3,389,704	$ (1,328,049)
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ (2,416,870)	$ (9,365,232)	$ (2,148,677)	$ (514,229)	$ 911,576	$ 597,713	$ 4,226,118	$ 5,501,863	$ (2,155,569)
Percent Increase @ System ROR	-12.09%	-9.70%	-3.60%	-12.49%	1.21%	1.84%	21.84%	35.59%	-22.19%
Maximum Increase @ 1 Times System Average Increase	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%	15.71%
Required Percentage Increase without Limitation	0.00%	0.00%	0.00%	0.00%	15.71%	15.71%	21.84%	35.59%	0.00%
Initial Increase					$ 11,818,082	$ 5,094,978	$ 3,040,467	$ 2,429,131	
Shortfall in Required Increase									
Step Two Increase									
Increase	$ 19,984,005	$ 96,564,184	$ 59,755,564	$ 4,117,348					$ 9,714,851
Allocation of Shortfall to Remaining Customer Classes	$ 3,139,832	$ 15,171,899	$ 9,388,630	$ 646,906					$ 1,526,371
Total Required Increase	$ 3,139,832	$ 15,171,899	$ 9,388,630	$ 646,906	$ 11,818,082	$ 5,094,978	$ 3,040,467	$ 2,429,131	$ 1,526,371
Proposed Revenue Allocation									
ROR	10.86%	10.15%	8.67%	10.90%	7.73%	7.60%	3.96%	3.27%	17.29%
Incremental Income	$ 1,934,454	$ 9,347,425	$ 5,784,346	$ 398,560	$ 7,281,134	$ 3,139,022	$ 1,873,236	$ 1,496,590	$ 940,399
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 3,139,832	$ 15,171,899	$ 9,388,630	$ 646,906	$ 11,818,082	$ 5,094,978	$ 3,040,467	$ 2,429,131	$ 1,526,371
Final Relative Rate of Return	1.37	1.28	1.09	1.37	0.97	0.96	0.50	0.41	2.18

Source: Company CCOSS; Company workpapers MO-RES-RD, MO-SGS (SGS-SGA), MO-MGS (MGS-MGA), MO-PGS (LGS-LGA), MO-LPS (LPS-LPA), MO-Lighting-TPP-Rate Design.

Recommended Revenue Distribution with Staff and OPC Adjustments to Revenue Requirements

		Residential				Small General Service				Medium General Service			
		Regular	Time of Day	All Electric	Separately Metered	Regular	Unmetered	All Electric	Separately Metered	Primary	Secondary	All Electric	Separately Meterd
Cost of Service Results													
Operating Income	$ 128,498,510	$ 29,036,340	$ 8,016	$ 7,320,279	$ 1,618,718	$ 9,625,170	$ 206,663	$ 336,022	$ 132,191	$ 194,337	$ 18,837,597	$ 1,669,770	$ 366,418
Rate Base	$ 2,557,069,761	$ 768,744,775	$ 217,191	$ 201,288,245	$ 56,568,952	$ 135,077,974	$ 2,378,997	$ 4,864,919	$ 1,899,035	$ 2,340,916	$ 292,380,477	$ 31,630,733	$ 6,376,026
ROR	5.03%	3.79%	3.69%	3.64%	2.86%	7.13%	8.69%	6.91%	6.96%	8.30%	6.44%	5.28%	5.75%
Relative Rate of Return	1.00	0.75	0.73	0.72	0.57	1.42	1.73	1.37	1.39	1.65	1.28	1.05	1.14
Revenue Requirement Results													
Operating Income	$ 148,765,442	$ 33,615,984	$ 9,280	$ 8,474,842	$ 1,874,024	$ 11,143,262	$ 239,258	$ 389,020	$ 153,041	$ 224,983	$ 21,808,684	$ 1,933,128	$ 424,210
Rate Base	$ 2,165,002,709	$ 655,174,267	$ 165,587	$ 171,998,405	$ 48,337,495	$ 115,422,518	$ 2,032,825	$ 4,157,015	$ 1,622,703	$ 2,000,265	$ 249,835,631	$ 27,028,084	$ 5,448,238
ROR	6.81%	5.13%	5.00%	4.93%	3.88%	9.65%	11.77%	9.36%	9.43%	11.25%	8.73%	7.15%	7.79%
Relative Rate of Return	1.00	0.75	0.73	0.72	0.57	1.42	1.73	1.37	1.39	1.65	1.28	1.06	1.14
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 21,119,735												
Operating Income Deficiency	$ 13,012,159												
ROR Schedule	6.81%												
Step One Increase													
System ROR	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
Incremental Income	$ 13,012,159	$ 10,991,416	$ 3,355	$ 3,235,633	$ 1,417,024	$ (3,284,745)	$ (100,653)	$ (105,990)	$ (42,559)	$ (68,799)	$ (4,798,676)	$ (92,926)	$ (53,268)
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 21,119,735	$ 17,839,913	$ 5,446	$ 5,251,681	$ 2,299,939	$ (5,331,394)	$ (163,693)	$ (172,031)	$ (69,077)	$ (144,127)	$ (7,768,624)	$ (150,826)	$ (86,458)
Percent Increase @ System ROR	2.74%	8.33%	9.18%	9.42%	15.51%	-11.66%	-17.31%	-10.89%	-11.04%	-17.52%	-8.54%	-1.63%	-4.52%
Maximum Increase @ the System Average Increase	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
Required Percentage Increase without Limitation	2.74%	2.74%	2.74%	2.74%	2.74%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Initial Increase	$ 11,729,366	$ 5,879,619	$ 1,628	$ 1,530,958	$ 407,011								
Shortfall in Required Increase	$ 9,390,369												
Step Two Increase													
Increase	$ 342,118,876	$ -	$ -	$ -	$ -	$ 45,638,828	$ 945,388	$ 1,579,169	$ 625,866	$ 822,432	$ 91,197,272	$ 9,260,995	$ 1,912,974
Allocation of Shortfall to Remaining Customer Classes	$ 9,390,369	$ -	$ -	$ -	$ -	$1,252,679.66	$ 25,949	$ 43,345	$ 17,179	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507
Total Required Increase	$ 21,119,735	$ 5,879,619	$ 1,628	$ 1,530,958	$ 407,011	$ 1,252,680	$ 25,949	$ 43,345	$ 17,179	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507
Proposed Revenue Allocation													
ROR	7.40%	5.66%	5.54%	5.46%	4.40%	10.32%	12.56%	10.00%	10.06%	11.94%	9.35%	7.73%	8.38%
Incremental Income	$ 13,012,159	$ 3,622,514	$ 1,003	$ 943,244	$ 250,765	$ 771,793	$ 15,987	$ 26,705	$ 10,584	$ 13,908	$ 1,542,227	$ 156,612	$ 32,350
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 21,119,735	$ 5,879,619	$ 1,628	$ 1,530,958	$ 407,011	$ 1,252,680	$ 25,949	$ 43,345	$ 17,179	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507
Final Relative Rate of Return	1.00	0.77	0.75	0.74	0.59	1.39	1.70	1.35	1.36	1.61	1.26	1.04	1.13

Recommended Revenue Distribution with Staff and OPC Adjustments to Revenue Requirements

Witness: Dismukes
ER-2014-0370
Schedule DED-7
Page 2 of 2

		Medium General Service				Large General Service				Large Power Service			All Lighting
	Primary	Secondary	All Electric	Separately Metered	Primary	Secondary	All Electric	Separately Metered	Primary	Secondary	Substation	Transmission	Lighting
Cost of Service Results													
Operating Income	$ 194,337	$ 18,837,597	$ 1,669,770	$ 366,418	$ 4,436,392	$ 20,589,253	$ 11,122,906	$ 928,391	$ 11,904,683	$ 5,037,549	$ 854,013	$ 2,016,097	$ 2,257,707
Rate Base	$ 2,340,916	$ 292,360,477	$ 31,630,733	$ 6,376,026	$ 58,651,655	$ 294,900,987	$ 194,999,832	$ 12,170,171	$ 248,076,520	$ 107,574,153	$ 68,607,989	$ 107,574,153	$ 18,499,982
ROR	8.30%	6.44%	5.28%	5.75%	7.56%	6.98%	5.70%	7.63%	4.80%	4.68%	1.24%	1.87%	12.20%
Relative Rate of Return	1.65	1.28	1.05	1.14	1.51	1.39	1.14	1.52	0.95	0.93	0.25	0.37	2.43
Revenue Requirement Results													
Operating Income	$ 224,958	$ 21,808,684	$ 1,933,128	$ 424,210	$ 5,136,105	$ 23,836,613	$ 12,877,224	$ 1,074,818	$ 13,782,303	$ 5,832,077	$ 958,709	$ 2,334,078	$ 2,613,795
Rate Base	$ 2,000,285	$ 249,835,631	$ 27,028,084	$ 5,448,238	$ 50,117,166	$ 251,939,377	$ 166,625,031	$ 10,399,266	$ 211,978,429	$ 91,920,831	$ 58,795,606	$ 91,920,831	$ 15,808,014
ROR	11.25%	8.73%	7.15%	7.79%	10.25%	9.46%	7.73%	10.34%	6.50%	6.34%	1.66%	2.54%	16.53%
Relative Rate of Return	1.65	1.28	1.05	1.14	1.51	1.39	1.14	1.52	0.95	0.93	0.25	0.37	2.43
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement													
Operating Income Deficiency													
ROR Schedule													
Step One Increase													
System ROR	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%	6.81%
Incremental Income	$ (88,799)	$ (4,798,678)	$ (92,926)	$ (53,268)	$ (1,723,689)	$ (6,679,970)	$ (1,532,594)	$ (366,786)	$ 650,203	$ 426,333	$ 3,014,377	$ 3,924,332	$ (1,537,510)
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ (144,127)	$ (7,788,624)	$ (150,826)	$ (86,458)	$ (2,798,004)	$ (10,842,106)	$ (2,487,518)	$ (595,322)	$ 1,055,329	$ 691,971	$ 4,892,566	$ 6,369,493	$ (2,495,497)
Percent Increase @ System ROR	-17.52%	-8.54%	-1.63%	-4.52%	-14.00%	-11.23%	-4.16%	-14.46%	1.40%	2.13%	25.28%	41.20%	-25.69%
Maximum Increase @ the System Average Increase	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
Required Percentage Increase without Limitation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.74%	2.74%	25.28%	41.20%	0.00%
Initial Increase									$ 2,064,566	$ 890,070	$ 531,156	$ 424,358	
Shortfall in Required Increase													
Step Two Increase													
Increase	$ 822,432	$ 91,197,272	$ 9,260,995	$ 1,912,974	$ 19,934,005	$ 96,564,184	$ 59,755,564	$ 4,117,348					$ 9,714,851
Allocation of Shortfall to Remaining Customer Classes	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507	$ 548,515	$ 2,650,463	$ 1,640,151	$ 113,012					$ 266,650
Total Required Increase	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507	$ 548,515	$ 2,650,463	$ 1,640,151	$ 113,012	$ 2,064,566	$ 890,070	$ 531,156	$ 424,358	$ 266,650
Proposed Revenue Allocation													
ROR	11.94%	9.35%	7.73%	8.38%	10.92%	10.11%	8.33%	11.01%	7.10%	6.94%	2.24%	2.82%	17.57%
Incremental Income	$ 13,908	$ 1,542,227	$ 156,612	$ 32,350	$ 337,947	$ 1,632,986	$ 1,010,520	$ 69,628	$ 1,272,007	$ 548,384	$ 327,253	$ 261,453	$ 164,287
Revenue Conversion Factor	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231	1.6231
Revenue Requirement	$ 22,574	$ 2,503,153	$ 254,193	$ 52,507	$ 548,515	$ 2,650,463	$ 1,640,151	$ 113,012	$ 2,064,566	$ 890,070	$ 531,156	$ 424,358	$ 266,650
Final Relative Rate of Return	1.61	1.26	1.04	1.13	1.48	1.37	1.13	1.49	0.96	0.94	0.30	0.38	2.37

Source: Company CCOSS; EMS ER-2014-0370-Direct 4-2-15.xls.

Company Current and Proposed Customer Charges

Description		Company's Present Charges		Company's Proposed Charges		Increase $	Increase %
Residential Service							
General Use, Other Use, All-Electric (one meter), SmartGrid Time of Use							
Customer Charge	$	9.00	$	25.00	$	16.00	177.8%
General Use All-Electric (two meter) - Rate C							
Customer Charge	$	9.00	$	25.00	$	16.00	177.8%
Second Meter	$	2.05	$	5.00	$	2.95	143.9%
Time-of-Day							
Customer Charge	$	14.04	$	25.00	$	10.96	78.1%
Small General Service (SGS)							
Primary, Secondary, All-Electric (one meter), All-Electric (two meters)							
Customer Charge							
Metered Service:							
0-24 kW	$	16.45	$	19.06	$	2.61	15.9%
25-199 kW	$	45.60	$	52.83	$	7.23	15.9%
200-999 kW	$	92.64	$	107.32	$	14.68	15.8%
1001+kW	$	790.99	$	916.32	$	125.33	15.8%
Unmetered Service	$	6.90	$	7.99	$	1.09	15.8%
Separately Metered Space Heat	$	2.12	$	2.46	$	0.34	16.0%
Medium General Service (MGS)							
Primary, Secondary, All-Electric (one meter), All-Electric (two meters)							
Customer Charge							
0-24 kW	$	47.67	$	55.35	$	7.68	16.1%
25-199 kW	$	47.67	$	55.35	$	7.68	16.1%
200-999 kW	$	96.82	$	112.43	$	15.61	16.1%
1001+kW	$	826.71	$	959.97	$	133.26	16.1%
Separately Metered Space Heat	$	2.22	$	2.58	$	0.36	16.2%
Large General Service (LGS)							
Primary, Secondary, All-Electric (one meter), All-Electric (two meters)							
Customer Charge							
0-24 kW	$	101.15	$	117.26	$	16.11	15.9%
25-199 kW	$	101.15	$	117.26	$	16.11	15.9%
200-999 kW	$	101.15	$	117.26	$	16.11	15.9%
1001+kW	$	863.59	$	1,001.15	$	137.56	15.9%
Separately Metered Space Heat	$	2.32	$	2.69	$	0.37	15.9%
Large Power Service (LPS)							
Primary, Secondary, Substation, Transmission							
Customer Charge	$	961.50	$	1,110.63	$	149.13	15.5%

Company Current and Proposed Customer Charges

Description	Company's Present Charges		Company's Proposed Charges		Increase $		Increase %
Private Unmetered Lighting Service (AL)							
Base Charge							
5800 Lumen High Pressure Sodium	$	20.63	$	23.88	$	3.25	15.8%
8600 Lumen Mercury Vapor	$	21.69	$	25.11	$	3.42	15.8%
16000 Lumen High Pressure Sodium	$	23.62	$	27.34	$	3.72	15.7%
22500 Lumen Mercury Vapor	$	26.55	$	30.74	$	4.19	15.8%
22500 Lumen Mercury Vapor	$	26.55	$	30.74	$	4.19	15.8%
27500 Lumen High Pressure Sodium	$	25.11	$	29.07	$	3.96	15.8%
50000 Lumen High Pressure Sodium	$	27.40	$	31.72	$	4.32	15.8%
63000 Lumen Mercury Vapor	$	34.50	$	39.94	$	5.44	15.8%
Additional Charges							
Each 30-foot ornamental steel pole installed	$	6.34	$	7.34	$	1.00	15.8%
Each 35-foot ornamental steel pole installed	$	7.23	$	8.37	$	1.14	15.8%
Each 30-foot wood pole installed	$	4.85	$	5.61	$	0.76	15.7%
Each 35-foot wood pole installed	$	5.30	$	6.14	$	0.84	15.8%
Each overhead span of circuit installed	$	3.55	$	4.11	$	0.56	15.8%
Underground lighting unit (per month)	$	2.71	$	3.14	$	0.43	15.9%

Company Current and Proposed Customer Charges

Description	Company's Present Charges		Company's Proposed Charges		Increase $		Increase %
Municipal Street Lighting Service (ML)							
Mercury Vapor and High Pressure Sodium Vapor							
8600 Lumen Mercury Vapor	$	236.88	$	274.20	$	37.32	15.8%
8600 Lumen Mercury Vapor - Twin	$	473.76	$	548.40	$	74.64	15.8%
12,100 Lumen Mercury Vapor	$	265.68	$	307.56	$	41.88	15.8%
12,100 Lumen Mercury Vapor - Twin	$	531.36	$	615.12	$	83.76	15.8%
22,500 Lumen Mercury Vapor	$	289.68	$	335.40	$	45.72	15.8%
22,500 Lumen Mercury Vapor - Twin	$	579.36	$	670.80	$	91.44	15.8%
9500 Lumen High Pressure Sodium	$	231.24	$	267.72	$	36.48	15.8%
9500 Lumen High Pressure Sodium - Twin	$	462.48	$	535.44	$	72.96	15.8%
16,000 Lumen High Pressure Sodium	$	257.64	$	298.32	$	40.68	15.8%
16,000 Lumen High Pressure Sodium - Twin	$	515.28	$	596.64	$	81.36	15.8%
27,500 Lumen High Pressure Sodium	$	273.84	$	317.04	$	43.20	15.8%
27,500 Lumen High Pressure Sodium - Twin	$	547.68	$	634.08	$	86.40	15.8%
50,000 Lumen High Pressure Sodium	$	298.68	$	345.84	$	47.16	15.8%
50,000 Lumen High Pressure Sodium - Twin	$	597.36	$	691.68	$	94.32	15.8%
Optional Equipment							
Ornamental Steel Pole	$	16.08	$	18.60	$	2.52	15.7%
Aluminum Pole	$	40.44	$	46.80	$	6.36	15.7%
Underground Svc Under Sod	$	68.04	$	78.72	$	10.68	15.7%
Underground Svc Under Concrete	$	259.80	$	300.72	$	40.92	15.8%
Breakaway Base	$	37.20	$	43.08	$	5.88	15.8%
Energy for Customer-Owned Lighting	$	0.07	$	0.08	$	0.01	15.8%
Code CX (single) (799 kwh per year)	$	56.73	$	65.68	$	8.95	15.8%
Code TCX (twin) (1598 kwh per year)	$	113.46	$	131.35	$	17.89	15.8%
Energy for Customer-Owned Lighting	$	0.07	$	0.08	$	0.01	15.8%
9500 Lumen High Pressure Sodium	$	136.20	$	157.68	$	21.48	15.8%
16000 Lumen High Pressure Sodium	$	225.60	$	261.12	$	35.52	15.7%
8600 Lumen - Limited Maintenance	$	115.20	$	133.32	$	18.12	15.7%
22500 Lumen - Limited Maintenance	$	250.56	$	290.04	$	39.48	15.8%
9500 Lumen - Limited Maintenance	$	115.20	$	133.32	$	18.12	15.7%
27500 Lumen - Limited Maintenance	$	250.56	$	290.04	$	39.48	15.8%

Company Current and Proposed Customer Charges

Description	Company's Present Charges	Company's Proposed Charges	Increase $	Increase %
Light Emitting Diode (LED)				
Small LED (≤ 7000 lumens) - Single	$ 231.24	$ 267.72	$ 36.48	15.8%
Small LED (≤ 7000 lumens) - Twin	$ 462.48	$ 535.44	$ 72.96	15.8%
Large LED (> 7000 lumens) - Single	$ 257.64	$ 298.32	$ 40.68	15.8%
Large LED (> 7000 lumens) - Twin	$ 515.28	$ 596.64	$ 81.36	15.8%
Optional Equipment				
Ornamental steel pole	$ 16.08	$ 18.60	$ 2.52	15.7%
Aluminum pole	$ 40.44	$ 46.80	$ 6.36	15.7%
Underground service extension - under sod	$ 68.04	$ 78.72	$ 10.68	15.7%
Underground service extension - under concrete	$ 259.80	$ 300.72	$ 40.92	15.8%
Breakaway base	$ 37.20	$ 43.08	$ 5.88	15.8%

Source: Company Workpapers, MO-Res-RD; MO SGS (SGS-SGA); MO MGS (MGS-MGA); MO LGS (LGS-LGA); MO LPS (LPS-LPA); MO Lighting-TPP – Rate Design.

Company Current and Proposed Customer Charges

Description		Company's Present Charges		Company's Proposed Charges	Increase $		Increase %
Municipal Traffic Control Signal Service (TR)							
Basic Installation							
Individual Control	$	174.73	$	202.29	$	27.56	15.8%
Suspension Control [1]	$	80.21	$	92.86	$	12.65	15.8%
1-Way, 1-Light Signal Unit	$	41.16	$	47.65	$	6.49	15.8%
4-Way, 1-Light Signal Unit - Suspension	$	48.72	$	56.40	$	7.68	15.8%
Pedestrian Push Button Control	$	146.24	$	169.30	$	23.06	15.8%
Coordinated Multi-Dial Control [1]	$	257.86	$	298.53	$	40.67	15.8%
Multi-Phase Electronic Control	$	421.97	$	488.52	$	66.55	15.8%
Supplemental Equipment							
Multi-Dial Controller [1]	$	18.04	$	20.88	$	2.84	15.7%
Coordinating Cable Connection [1]	$	20.51	$	23.74	$	3.23	15.7%
Excess Coordinating Cable - Under sod [1]	$	0.15	$	0.17	$	0.02	13.3%
Excess Coordinating Cable - Under concrete [1]	$	0.45	$	0.52	$	0.07	15.6%
3-Light Signal Unit	$	24.86	$	28.78	$	3.92	15.8%
2-Light Signal Unit	$	23.92	$	27.69	$	3.77	15.8%
1-Light Signal Unit	$	7.49	$	8.67	$	1.18	15.8%
Pedestrian Control Equipment-Push Buttons	$	3.34	$	3.87	$	0.53	15.9%
12-Inch Round Lens	$	6.07	$	7.03	$	0.96	15.8%
9-Inch Square Lens	$	6.87	$	7.95	$	1.08	15.7%
Directional Louvre [1]	$	1.49	$	1.72	$	0.23	15.4%
Vehicle - Actuation Unit - Loop Detector-Single	$	31.10	$	36.00	$	4.90	15.8%
Vehicle - Actuation Unit - Loop Detector-Double	$	49.35	$	57.13	$	7.78	15.8%
Flasher Equipment	$	8.83	$	10.22	$	1.39	15.7%
Mast Arm - Style 2	$	41.33	$	47.85	$	6.52	15.8%
Mast Arm - Style 3	$	40.96	$	47.42	$	6.46	15.8%
Back Plate	$	1.89	$	2.19	$	0.30	15.9%
Wood Pole Suspension	$	19.15	$	22.17	$	3.02	15.8%
Steel Pole Suspension [1]	$	46.22	$	53.51	$	7.29	15.8%
Pedestrian Timer [1]	$	10.85	$	12.56	$	1.71	15.8%
Traffic Signal Pole	$	10.50	$	12.16	$	1.66	15.8%

[1] The Company is recommending discontinuation of this rate.
Source: Company Workpapers, MO-Res-RD; MO SGS (SGS-SGA); MO MGS (MGS-MGA); MO LGS (LGS-LGA); MO LPS (LPS-LPA); MO Lighting-TPP – Rate Design.

Survey of Residential and Small Commercial Customer Charges

State	Company	Customer Charge ($/Month) Residential		Commercial	
IA	Amana Society Service Co[1]		NA		NA
IA	Interstate Power and Light Co	$	10.50	$	17.80
IA	MidAmerican Energy Co	$	8.50	$	10.00
IL	Ameren Illinois Company	$	10.57	$	19.44
IL	Commonwealth Edison Co	$	10.96	$	11.95
IL	MidAmerican Energy Co	$	7.25	$	18.07
IL	Mt. Carmel Public Utility	$	8.00	$	20.00
IN	Duke Energy Indiana Inc	$	9.40	$	9.40
IN	Indiana Michigan Power Co	$	7.30	$	10.90
IN	Indianapolis Power & Light Co[2]	$	6.70	$	11.38
IN	Northern Indiana Pub Service Co	$	11.00	$	20.00
IN	Southern Indiana Gas & Electric Co	$	11.00	$	11.00
KS	Empire District Electric Co	$	14.00	$	19.00
KS	Kansas City Power & Light Co	$	10.71	$	17.54
KS	Westar Energy Inc	$	12.00	$	20.00
MI	Alpena Power Co	$	5.00	$	7.00
MI	Consumers Energy Co	$	7.00	$	20.00
MI	Indiana Michigan Power Co	$	7.25	$	6.25
MI	Northern States Power Co	$	8.25	$	10.50
MI	The DTE Electric Company	$	6.00	$	8.78

[1] Amana Society Service Co. is not regulated by the Iowa Utilities Board.
[2] Indianapolis Power & Light Co. rate reflects a residential customer using 0-345 kWh in a month. The customer charge for usage over 345 kWh is $11.

Survey of Residential and Small Commercial Customer Charges

State	Company	Customer Charge ($/Month) Residential		Commercial	
MI	Upper Peninsula Power Co	$	12.00	$	16.00
MI	Wisconsin Electric Power Co	$	9.61	$	15.00
MI	Wisconsin Public Service Corp[1]	$	9.00	$	22.00
MN	Interstate Power and Light Co	$	8.50	$	21.33
MN	Minnesota Power Co	$	8.00	$	10.50
MN	Northern States Power Co - Minnesota[2]	$	8.00	$	10.00
MN	Northwestern Wisconsin Electric Co[3]	$	7.50	$	15.00
MN	Otter Tail Power Co	$	8.50	$	15.50
MO	Empire District Electric Co	$	12.52	$	21.32
MO	KCP&L Greater Missouri Operations Co[4]	$	10.43	$	17.19
MO	Kansas City Power & Light Co	$	9.00	$	16.45
MO	Union Electric Co - Missouri	$	8.00	$	9.74
ND	Montana-Dakota Utilities Co	$	10.65	$	21.30
ND	Northern States Power Co - North Dakota	$	14.50	$	16.75
ND	Otter Tail Power Co	$	8.00	$	13.00
OH	Cleveland Electric Illum Co	$	4.00	$	7.00
OH	Dayton Power & Light Co	$	4.25	$	8.66
OH	Duke Energy Ohio Inc	$	6.00	$	8.07
OH	Ohio Edison Co	$	4.00	$	7.00
OH	Ohio Power Co	$	8.40	$	13.17

[1] Wisconsin Public Service Corp. has a separate tariff for urban and rural customers. The table reflects the urban customer charge. The Rural Residential customer charge is $11.00 and the Rural Small Commercial customer charge is $24.00.
[2] Minnesota imposes separate customer charges for residential customers based on overhead or underground service. The table reflects the rate for Residential customers served by overhead lines. The underground service customer charge is $10.00.
[3] The Northwestern Wisconsin Electric Co. has a separate tariff rate for urban and rural customers. The table reflects the urban customer charge. The Rural Residential customer charge is $8.50.
[4] KCP&L Greater Missouri Operations Co. providese tariffs for two separate territories, L&P and MPS. The table reflects the rates for MPS. The Residential and General Service rates of the L&P territory are $9.54 and $18.85, respectively.

Survey of Residential and Small Commercial Customer Charges

State	Company	Customer Charge ($/Month) Residential	Commercial
OH	The Toledo Edison Co	$ 4.00	$ 7.00
SD	Black Hills Power Inc	$ 10.00	$ 12.50
SD	MidAmerican Energy Co	$ 8.23	$ 11.75
SD	Montana-Dakota Utilities Co	$ 6.00	$ 12.00
SD	NorthWestern Energy Co - (SD)	$ 5.00	$ 8.00
SD	Northern States Power Co - South Dakota[1]	$ 8.25	$ 9.00
SD	Otter Tail Power Co	$ 8.00	$ 13.00
WI	Consolidated Water Power Co	$ 6.00	$ 6.00
WI	Dahlberg Light & Power Co	$ 8.50	$ 11.00
WI	Madison Gas & Electric Co	$ 19.00	$ 23.93
WI	North Central Power Co Inc	$ 11.25	$ 20.00
WI	Northern States Power co	$ 8.00	$ 8.00
WI	Northwestern Wisconsin Electric Co	$ 7.50	$ 15.00
WI	Pioneer Power and Light Co	$ 6.00	$ 8.00
WI	Superior Water and Light Co	$ 7.00	$ 8.00
WI	Westfield Electric Company	$ 7.00	$ 7.00
WI	Wisconsin Electric Power Co	$ 16.00	$ 16.00
WI	Wisconsin Power & Light Co	$ 7.67	$ 7.67
WI	Wisconsin Public Service Corp	$ 19.00	$ 25.00

[1] South Dakota imposes separate customer charges for residential customers based on overhead or underground service. The table reflects the rate for residential customers served by overhead lines. The Underground service customer charge is $10.25.
Source: Company Tariff Books.

Current Customer Charges as Percent of Total Revenue

	Residential (R)	Small General Service (SGS)	Medium General Service (MGS)	Large General Service (LGS)	Large Power Service (LPS)
Customer Charge Revenue	$ 26,381,178	$ 5,586,529	$ 3,161,255	$ 2,186,994	$ 908,618
Total Revenue	$ 284,877,155	$ 48,789,254	$ 103,193,673	$ 180,421,101	$ 142,458,316
Customer Charge as Percent of Cost of Service	9.3%	11.5%	3.1%	1.2%	0.6%

Source: Company Workpapers, MO-Res-RD; MO SGS (SGS-SGA); MO MGS (MGS-MGA); MO LGS (LGS-LGA); MO LPS (LPS-LPA).

Total Distribution Bill Charges under Company's Proposed Rates

	Customer 1 Hypothetical Typical User		Customer 2 One-Third Less Than Typical User		Customer 3 One-Third Greater Than System Average	
Residential General Use						
Average Usage per Month (kWh)	825		550		1100	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475
Average Monthly Utility Bill Under Existing Rates	$ 109.30	$ 89.32	$ 75.86	$ 69.11	$ 142.73	$ 106.26
Proposed Customer Charge	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Proposed Volumetric Rate 1st Block (first 600 kWh)	$ 0.12712	$ 0.09737	$ 0.12712	$ 0.09737	$ 0.12712	$ 0.09737
Proposed Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548
Proposed Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12712	$ 0.05423	$ 0.12712	$ 0.05423	$ 0.12712	$ 0.05423
Average Monthly Utility Bill Under Proposed Rates	$ 129.87	$ 100.41	$ 94.92	$ 78.55	$ 164.83	$ 119.04
Percent Increase from Existing Rates to Proposed Rates	18.8%	12.4%	25.1%	13.7%	15.5%	12.0%
Residential General Use Space Heat - One Meter						
Average Usage per Month (kWh)	1135		760		1515	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05370	$ 0.12157	$ 0.05370	$ 0.12157	$ 0.05370
Average Monthly Utility Bill Under Existing Rates	$ 146.98	$ 101.69	$ 101.39	$ 73.93	$ 193.18	$ 122.10
Proposed Customer Charge	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Proposed Volumetric Rate 1st Block (first 600 kWh)	$ 0.12712	$ 0.08544	$ 0.12712	$ 0.08544	$ 0.12712	$ 0.08544
Proposed Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548
Proposed Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12712	$ 0.05370	$ 0.12712	$ 0.05370	$ 0.12712	$ 0.05370
Average Monthly Utility Bill Under Proposed Rates	$ 169.28	$ 113.71	$ 121.61	$ 88.34	$ 217.59	$ 134.11
Percent Increase from Existing Rates to Proposed Rates	15.2%	11.8%	19.9%	19.5%	12.6%	9.8%

Total Distribution Bill Charges under Company's Proposed Rates

	Customer 1 Hypothetical Typical User		Customer 2 One-Third Less Than Typical User		Customer 3 One-Third Greater Than System Average	
Residential General Use Space Heat - Two Meter						
Average Usage per Month (kWh)	1290		860		1720	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Second Meter Charge	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475
Existing Separate Space Heating Rate		$ 0.05494		$ 0.05494		$ 0.05494
Average Monthly Utility Bill Under Existing Rates	$ 167.88	$ 166.78	$ 115.60	$ 127.45	$ 220.15	$ 204.88
Proposed Customer Charge	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Proposed Second Meter Charge	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
Proposed Volumetric Rate 1st Block (first 600 kWh)	$ 0.12712	$ 0.09737	$ 0.12712	$ 0.09737	$ 0.12712	$ 0.09737
Proposed Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548	$ 0.12712	$ 0.07548
Proposed Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12712	$ 0.05423	$ 0.12712	$ 0.05423	$ 0.12712	$ 0.05423
Proposed Separate Space Heating Rate		$ 0.05370		$ 0.05370		$ 0.05370
Average Monthly Utility Bill Under Proposed Rates	$ 193.98	$ 181.33	$ 139.32	$ 141.07	$ 248.65	$ 218.88
Percent Increase from Existing Rates to Proposed Rates	15.6%	8.7%	20.5%	10.7%	12.9%	6.8%
Residential Time of Day[1]						
Average Usage per Month (kWh)	1180		790		1575	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04
Existing Volumetric Rate 1st Block On Peak	$ 0.18643	$ 0.07677	$ 0.18643	$ 0.07677	$ 0.18643	$ 0.07677
Existing Volumetric Rate 2nd Block Off Peak	$ 0.10386	$ 0.07677	$ 0.10386	$ 0.07677	$ 0.10386	$ 0.07677
Average Monthly Utility Bill Under Existing Rates	$ 160.95	$ 104.63	$ 112.40	$ 74.69	$ 210.13	$ 134.95
Proposed Customer Charge	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Proposed Volumetric Rate 1st Block On Peak	$ 0.21583	$ 0.07677	$ 0.21583	$ 0.07677	$ 0.21583	$ 0.07677
Proposed Volumetric Rate 2nd Block Off Peak	$ 0.12024	$ 0.07677	$ 0.12024	$ 0.07677	$ 0.12024	$ 0.07677
Average Monthly Utility Bill Under Proposed Rates	$ 195.08	$ 115.59	$ 138.87	$ 85.65	$ 252.02	$ 145.91
Percent Increase from Existing Rates to Proposed Rates	21.2%	10.5%	23.6%	14.7%	19.9%	8.1%

[1] Residential Time of Day typical bills are determined assuming 25 percent on peak usage and 75 percent off peak usage based on the test year on peak and off peak energy usage from the Company's rate design workpapers.

Source: Company Workpaper MO RES-RD; Company's Current and Proposed Residential Tariffs; Company response to OPC DR 65, Attachment QOPC-65_MFR Revenue Summary KCPL MO-BDL.

Comparison of Customer Related Costs to Customer Charges

	Total MO	Residential (R)	Small General Service (SGS)	Medium General Service (MGS)	Large General Service (LGS)	Large Power Service (LPS)
Customer Related Costs per Company's CCOSS						
Customer Lighting Component	$ 3,142,046	$ 0	$ 0	$ (0)	$ (0)	$ (0)
Customer Service Component	$ 7,057,608	$ 5,277,279	$ 680,685	$ 1,099,644	$ 0	$ 0
Customer Meters Component	$ 14,093,509	$ 8,863,946	$ 3,345,765	$ 908,783	$ 518,824	$ 456,191
Customer Meter Reading Component	$ 3,139,409	$ 2,799,263	$ 268,394	$ 59,335	$ 11,463	$ 953
Customer Other Records and Collections	$ 11,882,810	$ 10,044,015	$ 1,234,326	$ 563,648	$ 39,227	$ 1,593
Customer Other Customer Accounts, Services and	$ 14,388,483	$ 9,498,921	$ 1,046,241	$ 886,466	$ 1,164,591	$ 1,792,265
Customer Sales Component	$ 378,238	$ 334,402	$ 34,981	$ 7,357	$ 1,389	$ 109
Customer Miscellaneous Other Component	$ 2,352,909	$ 2,172,460	$ 144,031	$ 30,315	$ 5,723	$ 379
Total Customer-Related Costs	$ 56,435,012	$ 38,990,286	$ 6,754,423	$ 3,555,549	$ 1,741,217	$ 2,251,491
Average No. Customers	275,378	240,014	25,516	5,401	1,021	81
Monthly Customer-Related Costs/Customer	$ 17.08	$ 13.54	$ 22.06	$ 54.86	$ 142.14	$ 2,318.73
Customer Charge Revenue	$ 38,224,573	$ 26,381,178	$ 5,586,529	$ 3,161,255	$ 2,186,994	$ 908,618
Monthly Customer Charge Revenue/Customer	$ 11.57	$ 9.16	$ 18.25	$ 48.77	$ 178.53	$ 935.75
Relationship of Customer Charge Revenues to Customer-Related Costs	68%	68%	83%	89%	126%	40%

Source: Company CCOSS.

Comparison of Typical Bill Impact at Various Usage Levels

	Customer 1 Hypothetical Typical User		Customer 2 One-Third Less Than Typical User		Customer 3 One-Third Greater Than System Average	
Residential General Use						
Average Usage per Month (kWh)	825		550		1100	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475
Average Monthly Utility Bill Under Existing Rates	$ 109.30	$ 89.32	$ 75.86	$ 69.11	$ 142.73	$ 106.26
Alternative Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Alternative Volumetric Rate 1st Block (first 600 kWh)	$ 0.14272	$ 0.12830	$ 0.14272	$ 0.12830	$ 0.14272	$ 0.12830
Alternative Volumetric Rate 2nd Block (next 400 kWh)	$ 0.14272	$ 0.07692	$ 0.14272	$ 0.07692	$ 0.14272	$ 0.07692
Alternative Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.14272	$ 0.06427	$ 0.14272	$ 0.06427	$ 0.14272	$ 0.06427
Average Monthly Utility Bill Under Proposed Rates	$ 126.74	$ 103.29	$ 87.50	$ 79.57	$ 165.99	$ 123.18
Percent Increase from Existing Rates to Proposed Rates	16.0%	15.6%	15.3%	15.1%	16.3%	15.9%
Residential General Use Space Heat - One Meter						
Average Usage per Month (kWh)	1135		760		1515	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544	$ 0.12157	$ 0.08544
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05370	$ 0.12157	$ 0.05370	$ 0.12157	$ 0.05370
Average Monthly Utility Bill Under Existing Rates	$ 146.98	$ 101.69	$ 101.39	$ 73.93	$ 193.18	$ 122.10
Alternative Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Alternative Volumetric Rate 1st Block (first 600 kWh)	$ 0.14272	$ 0.10005	$ 0.14272	$ 0.10005	$ 0.14272	$ 0.10005
Alternative Volumetric Rate 2nd Block (next 400 kWh)	$ 0.14272	$ 0.10005	$ 0.14272	$ 0.10005	$ 0.14272	$ 0.10005
Alternative Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.14272	$ 0.06288	$ 0.14272	$ 0.06288	$ 0.14272	$ 0.06288
Average Monthly Utility Bill Under Proposed Rates	$ 170.99	$ 117.54	$ 117.47	$ 85.04	$ 225.22	$ 141.43
Percent Increase from Existing Rates to Proposed Rates	16.3%	15.6%	15.9%	15.0%	16.6%	15.8%

Comparison of Typical Bill Impact at Various Usage Levels

	Customer 1		Customer 2		Customer 3	
	Hypothetical Typical User		One-Third Less Than Typical User		One-Third Greater Than System Average	
Residential General Use Space Heat - Two Meter						
Average Usage per Month (kWh)	1290		860		1720	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Existing Second Meter Charge	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05
Existing Volumetric Rate 1st Block (first 600 kWh)	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929	$ 0.12157	$ 0.10929
Existing Volumetric Rate 2nd Block (next 400 kWh)	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552	$ 0.12157	$ 0.06552
Existing Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475	$ 0.12157	$ 0.05475
Existing Separate Space Heating Rate		$ 0.05494		$ 0.05494		$ 0.05494
Average Monthly Utility Bill Under Existing Rates	$ 167.88	$ 104.48	$ 115.60	$ 71.61	$ 220.15	$ 137.07
Alternative Customer Charge	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00	$ 9.00
Alternative Second Meter Charge	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05	$ 2.05
Alternative Volumetric Rate 1st Block (first 600 kWh)	$ 0.14272	$ 0.12830	$ 0.14272	$ 0.12830	$ 0.14272	$ 0.12830
Alternative Volumetric Rate 2nd Block (next 400 kWh)	$ 0.14272	$ 0.07692	$ 0.14272	$ 0.07692	$ 0.14272	$ 0.07692
Alternative Volumetric Rate 3rd Block (over 1,000 kWh)	$ 0.14272	$ 0.06427	$ 0.14272	$ 0.06427	$ 0.14272	$ 0.06427
Alternative Separate Space Heating Rate		$ 0.06450		$ 0.06450		$ 0.06450
Average Monthly Utility Bill Under Proposed Rates	$ 195.16	$ 120.73	$ 133.79	$ 82.15	$ 256.53	$ 158.99
Percent Increase from Existing Rates to Proposed Rates	16.3%	15.6%	15.7%	14.7%	16.5%	16.0%
Residential Time of Day[1]						
Average Usage per Month (kWh)	1180		790		1575	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Customer Charge	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04
Existing Volumetric Rate 1st Block On Peak	$ 0.18643	$ 0.07677	$ 0.18643	$ 0.07677	$ 0.18643	$ 0.07677
Existing Volumetric Rate 2nd Block Off Peak	$ 0.10386	$ 0.07677	$ 0.10386	$ 0.07677	$ 0.10386	$ 0.07677
Average Monthly Utility Bill Under Existing Rates	$ 160.95	$ 104.63	$ 112.40	$ 74.69	$ 210.13	$ 134.95
Alternative Customer Charge	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04	$ 14.04
Alternative Volumetric Rate 1st Block On Peak	$ 0.21932	$ 0.09032	$ 0.21932	$ 0.09032	$ 0.21932	$ 0.09032
Alternative Volumetric Rate 2nd Block Off Peak	$ 0.12218	$ 0.09032	$ 0.12218	$ 0.09032	$ 0.12218	$ 0.09032
Average Monthly Utility Bill Under Proposed Rates	$ 186.87	$ 120.61	$ 129.75	$ 85.39	$ 244.73	$ 156.29
Percent Increase from Existing Rates to Proposed Rates	16.1%	15.3%	15.4%	14.3%	16.5%	15.8%

[1] Residential Time of Day typical bills are determined assuming 25 percent on peak usage and 75 percent off peak usage based on the test year on peak and off peak energy usage from the Company's rate design workpapers.
Source: Company Workpaper MO RES-RD; Company's Current and Proposed Residential Tariffs; Company response to OPC DR 65, Attachment QOPC-65_MFR Revenue Summary KCPL MO-BDL.

Comparison of Alternative Rates to Current and Proposed Rates

Witness: Dismukes
ER-2014-0370
Schedule DED-14

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Residential Service								
General Use - Rate A								
Customer Charge	$9.00	$25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 2nd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 3rd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Winter Energy Rate 1st Block	$ 0.10929	$ 0.09737	$ (0.01)	-10.9%	$ 0.12830	17.4%	$ 0.11263	3.1%
Winter Energy Rate 2nd Block	$ 0.06552	$ 0.07548	$ 0.01	15.2%	$ 0.07692	17.4%	$ 0.06752	3.1%
Winter Energy Rate 3rd Block	$ 0.05475	$ 0.05423	$ (0.00)	-0.9%	$ 0.06427	17.4%	$ 0.05642	3.1%
General Use w/ Space Heat (one meter) - Rate B								
Customer Charge	$ 9.00	$ 25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 2nd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 3rd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Winter Energy Rate 1st Block	$ 0.08544	$ 0.08544	$ -	0.0%	$ 0.10005	17.1%	$ 0.08799	3.0%
Winter Energy Rate 2nd Block	$ 0.08544	$ 0.07548	$ (0.01)	-11.7%	$ 0.10005	17.1%	$ 0.08799	3.0%
Winter Energy Rate 3rd Block	$ 0.05370	$ 0.05370	$ -	0.0%	$ 0.06288	17.1%	$ 0.05530	3.0%
General Use with Space Heat (two meter) - Rate C								
Customer Charge	$ 9.00	$ 25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Second Meter	$ 2.05	$ 5.00	$ 2.95	143.9%	$ 2.05	0.0%	$ 2.05	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 2nd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Summer Energy Rate 3rd Block	$ 0.12157	$ 0.12712	$ 0.01	4.6%	$ 0.14272	17.4%	$ 0.12529	3.1%
Winter Energy Rate 1st Block	$ 0.10929	$ 0.09737	$ (0.01)	-10.9%	$ 0.12830	17.4%	$ 0.11263	3.1%
Winter Energy Rate 2nd Block	$ 0.06552	$ 0.07548	$ 0.01	15.2%	$ 0.07692	17.4%	$ 0.06752	3.1%
Winter Energy Rate 3rd Block	$ 0.05475	$ 0.05423	$ (0.00)	-0.9%	$ 0.06427	17.4%	$ 0.05642	3.1%
Space Heating Rate	$ 0.05494	$ 0.05370	$ (0.00)	-2.3%	$ 0.06450	17.4%	$ 0.05662	3.1%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Residential Service								
Time-of-Day								
Customer Charge	$ 14.04	$ 25.00	$ 10.96	78.1%	$ 14.04	0.0%	$ 14.04	0.0%
Energy Charge								
Summer Energy Rate On Peak	$ 0.18643	$ 0.21583	$ 0.03	15.8%	$ 0.21932	17.6%	$ 0.19218	3.1%
Summer Energy Rate Off Peak	$ 0.10386	$ 0.12024	$ 0.02	15.8%	$ 0.12218	17.6%	$ 0.10706	3.1%
Winter Energy Rate All kWh	$ 0.07677	$ 0.07677	$ -	0.0%	$ 0.09032	17.6%	$ 0.07914	3.1%
Other Use								
Customer Charge	$ 9.00	$ 25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Energy Charge								
Summer Energy Rate All kWh	$ 0.15789	$ 0.15536	$ (0.00)	-1.6%	$ 0.15754	-0.2%	$ 0.13830	-12.4%
Winter Energy Rate All kWh	$ 0.12268	$ 0.12929	$ 0.01	105.4%	$ 0.13111	6.9%	$ 0.11510	-6.2%
SmartGrid Time-of-Use (General)								
Customer Charge	$ 9.00	$ 25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Energy Charge								
Summer Energy Rate On Peak	$ 0.37840	$ 0.12712	$ (0.25)	-66.4%	$ 0.14272	-62.3%	$ 0.12529	-66.9%
Summer Energy Rate Off Peak	$ 0.06310	$ 0.12712	$ 0.06	101.5%	$ 0.14272	126.2%	$ 0.12529	98.6%
Winter Energy Rate 1st Block	$ 0.09914	$ 0.09737	$ (0.00)	-1.8%	$ 0.12830	29.4%	$ 0.11263	13.6%
Winter Energy Rate 2nd Block	$ 0.05945	$ 0.07548	$ 0.02	27.0%	$ 0.07692	29.4%	$ 0.06752	13.6%
Winter Energy Rate 3rd Block	$ 0.04968	$ 0.05423	$ 0.00	9.2%	$ 0.06427	29.4%	$ 0.05642	13.6%
SmartGrid Time-of-Use (General/Space Heat one meter)								
Customer Charge	$ 9.00	$ 25.00	$ 16.00	177.8%	$ 9.00	0.0%	$ 9.00	0.0%
Energy Charge								
Summer Energy Rate On Peak	$ 0.37840	$ 0.12712	$ (0.25)	-66.4%	$ 0.14272	-62.3%	$ 0.12529	-66.9%
Summer Energy Rate Off Peak	$ 0.06310	$ 0.12712	$ 0.06	101.5%	$ 0.14272	126.2%	$ 0.12529	98.6%
Winter Energy Rate 1st Block	$ 0.07382	$ 0.08544	$ 0.01	15.7%	$ 0.10005	35.5%	$ 0.08799	19.2%
Winter Energy Rate 2nd Block	$ 0.04872	$ 0.05370	$ 0.00	10.2%	$ 0.06288	29.1%	$ 0.05530	13.5%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Small General Service								
SGS - Primary								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14346	$ 0.16623	$ 0.02	15.9%	$ 0.16906	17.8%	$ 0.14801	3.2%
Summer Energy Rate 2nd Block	$ 0.06807	$ 0.07886	$ 0.01	15.9%	$ 0.08022	17.8%	$ 0.07023	3.2%
Summer Energy Rate 3rd Block	$ 0.06063	$ 0.07024	$ 0.01	15.9%	$ 0.07145	17.8%	$ 0.06255	3.2%
Winter Energy Rate 1st Block	$ 0.11148	$ 0.12914	$ 0.02	15.8%	$ 0.13137	17.8%	$ 0.11501	3.2%
Winter Energy Rate 2nd Block	$ 0.05442	$ 0.06304	$ 0.01	15.8%	$ 0.06413	17.8%	$ 0.05615	3.2%
Winter Energy Rate 3rd Block	$ 0.04910	$ 0.05688	$ 0.01	15.8%	$ 0.05786	17.8%	$ 0.05066	3.2%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%	$ -	0.0%	$ -	0
26+ kW	$ 2.5880	$ 2.9980	$ 0.41	15.8%	$ 3.0498	17.8%	$ 2.67	3.2%
SGS - Secondary								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14682	$ 0.17012	$ 0.02	15.9%	$ 0.17302	17.8%	$ 0.15147	3.2%
Summer Energy Rate 2nd Block	$ 0.06966	$ 0.08070	$ 0.01	15.8%	$ 0.08209	17.8%	$ 0.07187	3.2%
Summer Energy Rate 3rd Block	$ 0.06207	$ 0.07190	$ 0.01	15.8%	$ 0.07315	17.8%	$ 0.06404	3.2%
Winter Energy Rate 1st Block	$ 0.11408	$ 0.13216	$ 0.02	15.8%	$ 0.13444	17.8%	$ 0.11770	3.2%
Winter Energy Rate 2nd Block	$ 0.05570	$ 0.06453	$ 0.01	15.9%	$ 0.06564	17.8%	$ 0.05747	3.2%
Winter Energy Rate 3rd Block	$ 0.05027	$ 0.05824	$ 0.01	15.9%	$ 0.05924	17.8%	$ 0.05186	3.2%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%	$ -		$ -	0.0%
26+ kW	$ 2.65	$ 3.07	$ 0.42	15.8%	$ 3.12	17.8%	$ 2.73	3.2%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Small General Service								
SGS - Primary All Electric (one meter)								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14346	$ 0.16623	$ 0.02	15.9%	$ 0.16906	17.8%	$ 0.14801	3.2%
Summer Energy Rate 2nd Block	$ 0.06807	$ 0.07886	$ 0.01	15.9%	$ 0.08022	17.8%	$ 0.07023	3.2%
Summer Energy Rate 3rd Block	$ 0.06063	$ 0.07024	$ 0.01	15.9%	$ 0.07145	17.8%	$ 0.06255	3.2%
Winter Energy Rate 1st Block	$ 0.09724	$ 0.11265	$ 0.02	15.8%	$ 0.11374	17.0%	$ 0.10012	3.0%
Winter Energy Rate 2nd Block	$ 0.05606	$ 0.06304	$ 0.01	12.5%	$ 0.06413	14.4%	$ 0.05615	0.2%
Winter Energy Rate 3rd Block	$ 0.05339	$ 0.05688	$ 0.00	6.5%	$ 0.05786	8.4%	$ 0.05066	-5.1%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%	$ -		$ -	0.0%
26+ kW	$ 2.58800	$ 2.99800	$ 0.41	15.8%	$ 3.05	17.8%	$ 2.67	3.2%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
SGS - Secondary All Electric (one meter)								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14682	$ 0.17012	$ 0.02	15.9%	$ 0.17302	17.8%	$ 0.15147	3.2%
Summer Energy Rate 2nd Block	$ 0.06966	$ 0.08070	$ 0.01	15.8%	$ 0.08209	17.8%	$ 0.07187	3.2%
Summer Energy Rate 3rd Block	$ 0.06207	$ 0.07190	$ 0.01	15.8%	$ 0.07315	17.8%	$ 0.06404	3.2%
Winter Energy Rate 1st Block	$ 0.09951	$ 0.11528	$ 0.02	15.8%	$ 0.11639	17.0%	$ 0.10246	3.0%
Winter Energy Rate 2nd Block	$ 0.05737	$ 0.06453	$ 0.01	12.5%	$ 0.06564	14.4%	$ 0.05747	0.2%
Winter Energy Rate 3rd Block	$ 0.05465	$ 0.05824	$ 0.00	6.6%	$ 0.05924	8.4%	$ 0.05186	-5.1%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%	$ -	0.0%	$ -	0.0%
26+ kW	$ 2.65	$ 3.07	$ 0.42	15.8%	$ 3.12	17.8%	$ 2.73	3.2%
SGS - Secondary All Electric (two meters)								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14682	$ 0.17012	$ 0.02	15.9%	$ 0.17302	17.8%	$ 0.15147	3.2%
Summer Energy Rate 2nd Block	$ 0.06966	$ 0.08070	$ 0.01	15.8%	$ 0.08209	17.8%	$ 0.07187	3.2%
Summer Energy Rate 3rd Block	$ 0.06207	$ 0.07190	$ 0.01	15.8%	$ 0.07315	17.8%	$ 0.06404	3.2%
Winter Energy Rate 1st Block	$ 0.11408	$ 0.13216	$ 0.02	15.8%	$ 0.13444	17.8%	$ 0.11770	3.2%
Winter Energy Rate 2nd Block	$ 0.05570	$ 0.06453	$ 0.01	15.9%	$ 0.06564	17.8%	$ 0.05747	3.2%
Winter Energy Rate 3rd Block	$ 0.05027	$ 0.05824	$ 0.01	0.0%	$ 0.05924	17.8%	$ 0.05186	3.2%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%	$ -		$ -	0.0%
26+ kW	$ 2.65	$ 3.07	$ 0.42	15.8%	$ 3.12	17.8%	$ 2.73	3.2%
Separately Metered Space Heat	$ 0.06109	$ 0.05824	$ (0.003)	-4.7%	$ 0.05924	-3.0%	$ 0.05186	-15.1%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
SGS - Secondary Unmetered								
Customer Charge								
Metered Service:								
0-24 kW	$ 16.45	$ 19.06	$ 2.61	15.9%	$ 16.45	0.0%	$ 16.45	0.0%
25-199 kW	$ 45.60	$ 52.83	$ 7.23	15.9%	$ 45.60	0.0%	$ 45.60	0.0%
200-999 kW	$ 92.64	$ 107.32	$ 14.68	15.8%	$ 92.64	0.0%	$ 92.64	0.0%
1001+kW	$ 790.99	$ 916.32	$ 125.33	15.8%	$ 790.99	0.0%	$ 790.99	0.0%
Unmetered Service	$ 6.90	$ 7.99	$ 1.09	15.8%	$ 6.90	0.0%	$ 6.90	0.0%
Separately Metered Space Heat	$ 2.12	$ 2.46	$ 0.34	16.0%	$ 2.12	0.0%	$ 2.12	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.14682	$ 0.17012	$ 0.02	15.9%	$ 0.17302	17.8%	$ 0.15147	3.2%
Summer Energy Rate 2nd Block	$ 0.06966	$ 0.08070	$ 0.01	15.8%	$ 0.08209	17.8%	$ 0.07187	3.2%
Summer Energy Rate 3rd Block	$ 0.06207	$ 0.07190	$ 0.01	15.8%	$ 0.07315	17.8%	$ 0.06404	3.2%
Winter Energy Rate 1st Block	$ 0.11408	$ 0.13216	$ 0.02	15.8%	$ 0.13444	17.8%	$ 0.11770	3.2%
Winter Energy Rate 2nd Block	$ 0.05570	$ 0.06453	$ 0.01	15.9%	$ 0.06564	17.8%	$ 0.05747	3.2%
Winter Energy Rate 3rd Block	$ 0.05027	$ 0.05824	$ 0.01	15.9%	$ 0.05924	17.8%	$ 0.05186	3.2%
Facilities Charge								
0-25 kW	$ -	$ -	$ -	0.0%			$ -	0.0%
26+ kW	$ 2.65	$ 3.07	$ 0.42	15.8%	$ 3.12	17.8%	$ 2.73	3.2%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Medium General Service (MGS)								
MGS - Primary								
Customer Charge								
0-24 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
25-199 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
200-999 kW	$ 96.82	$ 112.43	$ 15.61	16.1%	$ 96.82	0.0%	$ 96.82	0.0%
1001+kW	$ 826.71	$ 959.97	$ 133.26	16.1%	$ 826.71	0.0%	$ 826.71	0.0%
Separately Metered Space Heat	$ 2.22	$ 2.58	$ 0.36	16.2%	$ 2.22	0.0%	$ 2.22	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.09246	$ 0.10736	$ 0.01	16.1%	$ 0.10739	16.1%	$ 0.09507	2.8%
Summer Energy Rate 2nd Block	$ 0.06333	$ 0.07354	$ 0.01	16.1%	$ 0.07356	16.1%	$ 0.06512	2.8%
Summer Energy Rate 3rd Block	$ 0.05340	$ 0.06201	$ 0.01	16.1%	$ 0.06202	16.1%	$ 0.05491	2.8%
Winter Energy Rate 1st Block	$ 0.07993	$ 0.09281	$ 0.01	16.1%	$ 0.09284	16.1%	$ 0.08218	2.8%
Winter Energy Rate 2nd Block	$ 0.04786	$ 0.05557	$ 0.01	16.1%	$ 0.05559	16.1%	$ 0.04921	2.8%
Winter Energy Rate 3rd Block	$ 0.04030	$ 0.04680	$ 0.01	16.1%	$ 0.04681	16.1%	$ 0.04144	2.8%
Facilities Charge	$ 2.30	$ 2.67	$ 0.37	16.1%	$ 2.667	16.1%	$ 2.36	2.8%
Summer Demand Charge	$ 3.54	$ 4.11	$ 0.57	16.1%	$ 4.11	16.1%	$ 3.64	2.8%
Winter Demand Charge	$ 1.80	$ 2.09	$ 0.29	16.1%	$ 2.09	16.1%	$ 1.85	2.8%
Reactive Demand Adjustment	$ 0.694	$ 0.812	$ 0.12	17.0%	$ 0.806	16.1%	$ 0.71358	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Medium General Service (MGS)								
MGS - Secondary								
Customer Charge								
0-24 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
25-199 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
200-999 kW	$ 96.82	$ 112.43	$ 15.61	16.1%	$ 96.82	0.0%	$ 96.82	0.0%
1001+kW	$ 826.71	$ 959.97	$ 133.26	16.1%	$ 826.71	0.0%	$ 826.71	0.0%
Separately Metered Space Heat	$ 2.22	$ 2.58	$ 0.36	16.2%	$ 2.22	0.0%	$ 2.22	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.09473	$ 0.11000	$ 0.02	16.1%	$ 0.11021	16.3%	$ 0.09752	2.9%
Summer Energy Rate 2nd Block	$ 0.06479	$ 0.07523	$ 0.01	16.1%	$ 0.07538	16.3%	$ 0.06670	2.9%
Summer Energy Rate 3rd Block	$ 0.05464	$ 0.06345	$ 0.01	16.1%	$ 0.06357	16.3%	$ 0.05625	2.9%
Winter Energy Rate 1st Block	$ 0.08185	$ 0.09504	$ 0.01	16.1%	$ 0.09522	16.3%	$ 0.08426	2.9%
Winter Energy Rate 2nd Block	$ 0.04899	$ 0.05689	$ 0.01	16.1%	$ 0.05700	16.3%	$ 0.05043	2.9%
Winter Energy Rate 3rd Block	$ 0.04109	$ 0.04771	$ 0.01	16.1%	$ 0.04780	16.3%	$ 0.04230	2.9%
Facilities Charge	$ 2.770	$ 3.216	$ 0.45	16.1%	$ 3.223	16.3%	$ 2.85	2.9%
Summer Demand Charge	$ 3.624	$ 4.208	$ 0.58	16.1%	$ 4.22	16.3%	$ 3.73	2.9%
Winter Demand Charge	$ 1.844	$ 2.141	$ 0.30	16.1%	$ 2.15	16.3%	$ 1.90	2.9%
Reactive Demand Adjustment	$ 0.6940	$ 0.8118	$ 0.12	17.0%	$ 0.807	16.3%	$ 0.7144	2.9%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
MGS - Primary All Electric (one meter)								
Customer Charge								
0-24 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
25-199 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
200-999 kW	$ 96.82	$ 112.43	$ 15.61	16.1%	$ 96.82	0.0%	$ 96.82	0.0%
1001+kW	$ 826.71	$ 959.97	$ 133.26	16.1%	$ 826.71	0.0%	$ 826.71	0.0%
Separately Metered Space Heat	$ 2.22	$ 2.58	$ 0.36	16.2%	$ 2.22	0.0%	$ 2.22	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.09246	$ 0.10736	$ 0.015	16.1%	$ 0.10953	18.5%	$ 0.09700	4.9%
Summer Energy Rate 2nd Block	$ 0.06333	$ 0.07354	$ 0.010	16.1%	$ 0.07502	18.5%	$ 0.06644	4.9%
Summer Energy Rate 3rd Block	$ 0.05340	$ 0.06201	$ 0.009	16.1%	$ 0.06326	18.5%	$ 0.05602	4.9%
Winter Energy Rate 1st Block	$ 0.06686	$ 0.07764	$ 0.011	16.1%	$ 0.07920	18.5%	$ 0.07014	4.9%
Winter Energy Rate 2nd Block	$ 0.04007	$ 0.04653	$ 0.006	16.1%	$ 0.04747	18.5%	$ 0.04204	4.9%
Winter Energy Rate 3rd Block	$ 0.03500	$ 0.04064	$ 0.006	16.1%	$ 0.04146	18.5%	$ 0.03672	4.9%
Facilities Charge	$ 2.296	$ 2.666	$ 0.37	16.1%	$ 2.720	18.5%	$ 2.41	4.9%
Summer Demand Charge	$ 3.540	$ 4.111	$ 0.57	16.1%	$ 4.19	18.5%	$ 3.71	4.9%
Winter Demand Charge	$ 2.554	$ 2.090	$ (0.46)	-18.2%	$ 2.09	-18.1%	$ 1.85	-27.5%
MGS - Secondary All Electric (one meter)								
Customer Charge								
0-24 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
25-199 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
200-999 kW	$ 96.82	$ 112.43	$ 15.61	16.1%	$ 96.82	0.0%	$ 96.82	0.0%
1001+kW	$ 826.71	$ 959.97	$ 133.26	16.1%	$ 826.71	0.0%	$ 826.71	0.0%
Separately Metered Space Heat	$ 2.22	$ 2.58	$ 0.36	16.2%	$ 2.22	0.0%	$ 2.22	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.09473	$ 0.11000	$ 0.015	16.1%	$ 0.11222	18.5%	$ 0.09938	4.9%
Summer Energy Rate 2nd Block	$ 0.06479	$ 0.07523	$ 0.010	16.1%	$ 0.07675	18.5%	$ 0.06797	4.9%
Summer Energy Rate 3rd Block	$ 0.05464	$ 0.06345	$ 0.009	16.1%	$ 0.06473	18.5%	$ 0.05732	4.9%
Winter Energy Rate 1st Block	$ 0.06840	$ 0.07943	$ 0.011	16.1%	$ 0.08103	18.5%	$ 0.07176	4.9%
Winter Energy Rate 2nd Block	$ 0.04109	$ 0.04771	$ 0.007	16.1%	$ 0.04868	18.5%	$ 0.04311	4.9%
Winter Energy Rate 3rd Block	$ 0.03568	$ 0.04143	$ 0.006	16.1%	$ 0.04227	18.5%	$ 0.03743	4.9%
Facilities Charge	$ 2.770	$ 3.216	$ 0.45	16.1%	$ 3.28	18.5%	$ 2.91	4.9%
Summer Demand Charge	$ 3.624	$ 4.208	$ 0.58	16.1%	$ 4.29	18.5%	$ 3.80	4.9%
Winter Demand Charge	$ 2.611	$ 2.141	$ (0.47)	-18.0%	$ 2.15	-17.8%	$ 1.90	-27.3%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
MGS - Secondary Space Heating (two meters)								
Customer Charge								
0-24 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
25-199 kW	$ 47.67	$ 55.35	$ 7.68	16.1%	$ 47.67	0.0%	$ 47.67	0.0%
200-999 kW	$ 96.82	$ 112.43	$ 15.61	16.1%	$ 96.82	0.0%	$ 96.82	0.0%
1001+kW	$ 826.71	$ 959.97	$ 133.26	16.1%	$ 826.71	0.0%	$ 826.71	0.0%
Separately Metered Space Heat	$ 2.22	$ 2.58	$ 0.36	16.2%	$ 2.22	0.0%	$ 2.22	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.09473	$ 0.11000	$ 0.02	16.1%	$ 0.11021	16.3%	$ 0.09752	2.9%
Summer Energy Rate 2nd Block	$ 0.06479	$ 0.07523	$ 0.01	16.1%	$ 0.07538	16.3%	$ 0.06670	2.9%
Summer Energy Rate 3rd Block	$ 0.05464	$ 0.06345	$ 0.01	16.1%	$ 0.06357	16.3%	$ 0.05625	2.9%
Winter Energy Rate 1st Block	$ 0.08185	$ 0.09504	$ 0.01	16.1%	$ 0.09522	16.3%	$ 0.08426	2.9%
Winter Energy Rate 2nd Block	$ 0.04899	$ 0.05689	$ 0.01	16.1%	$ 0.05700	16.3%	$ 0.05043	2.9%
Winter Energy Rate 3rd Block	$ 0.04109	$ 0.04771	$ 0.01	16.1%	$ 0.04780	16.3%	$ 0.04230	2.9%
Facilities Charge	$ 2.770	$ 3.216	$ 0.45	16.1%	$ 3.223	16.3%	$ 2.85	2.9%
Summer Demand Charge	$ 3.624	$ 4.208	$ 0.58	16.1%	$ 4.216	16.3%	$ 3.73	2.9%
Winter Demand Charge	$ 1.844	$ 2.141	$ 0.30	16.1%	$ 2.145	16.3%	$ 1.90	2.9%
Separately Metered Space Heat	$ 0.0535	$ 0.0414	$ (0.01)	-22.6%	$ 0.0478	-10.7%	$ 0.04230	-21.0%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Large General Service (LGS)								
LGS- Primary								
Customer Charge								
0-24 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
25-199 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
200-999 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
1001+kW	$ 863.59	$ 1,001.15	$ 137.56	15.9%	$ 863.59	0.0%	$ 863.59	0.0%
Separately Metered Space Heat	$ 2.32	$ 2.69	$ 0.37	15.9%	$ 2.32	0.0%	$ 2.32	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.08296	$ 0.09617	$ 0.01	15.9%	$ 0.09618	15.9%	$ 0.08527	2.8%
Summer Energy Rate 2nd Block	$ 0.05930	$ 0.06875	$ 0.01	15.9%	$ 0.06875	15.9%	$ 0.06095	2.8%
Summer Energy Rate 3rd Block	$ 0.04160	$ 0.04823	$ 0.01	15.9%	$ 0.04823	15.9%	$ 0.04276	2.8%
Winter Energy Rate 1st Block	$ 0.07620	$ 0.08834	$ 0.01	15.9%	$ 0.08834	15.9%	$ 0.07832	2.8%
Winter Energy Rate 2nd Block	$ 0.04558	$ 0.05284	$ 0.01	15.9%	$ 0.05284	15.9%	$ 0.04685	2.8%
Winter Energy Rate 3rd Block	$ 0.03510	$ 0.04069	$ 0.01	15.9%	$ 0.04069	15.9%	$ 0.03608	2.8%
Facilities Charge	$ 2.399	$ 2.781	$ 0.38	15.9%	$ 2.781	15.9%	$ 2.47	2.8%
Summer Demand Charge	$ 5.647	$ 6.547	$ 0.90	15.9%	$ 6.547	15.9%	$ 5.804	2.8%
Winter Demand Charge	$ 3.039	$ 3.523	$ 0.48	15.9%	$ 3.523	15.9%	$ 3.12	2.8%
Reactive Demand Adjustment	$ 0.7260	$ 0.8434	$ 0.12	16.2%	$ 0.84155	15.9%	$ 0.74619	2.8%
LGS - Secondary								
Customer Charge								
0-24 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
25-199 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
200-999 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
1001+kW	$ 863.59	$ 1,001.15	$ 137.56	15.9%	$ 863.59	0.0%	$ 863.59	0.0%
Separately Metered Space Heat	$ 2.32	$ 2.69	$ 0.37	15.9%	$ 2.32	0.0%	$ 2.32	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.08486	$ 0.09838	$ 0.01	15.9%	$ 0.09859	16.2%	$ 0.08743	3.0%
Summer Energy Rate 2nd Block	$ 0.06075	$ 0.07043	$ 0.01	15.9%	$ 0.07058	16.2%	$ 0.06259	3.0%
Summer Energy Rate 3rd Block	$ 0.04260	$ 0.04939	$ 0.01	15.9%	$ 0.04949	16.2%	$ 0.04389	3.0%
Winter Energy Rate 1st Block	$ 0.07798	$ 0.09040	$ 0.01	15.9%	$ 0.09060	16.2%	$ 0.08035	3.0%
Winter Energy Rate 2nd Block	$ 0.04670	$ 0.05414	$ 0.01	15.9%	$ 0.05426	16.2%	$ 0.04812	3.0%
Winter Energy Rate 3rd Block	$ 0.03580	$ 0.04150	$ 0.01	15.9%	$ 0.04159	16.2%	$ 0.03689	3.0%
Facilities Charge	$ 2.894	$ 3.355	$ 0.46	15.9%	$ 3.362	16.2%	$ 2.98	3.0%
Summer Demand Charge	$ 5.778	$ 6.698	$ 0.92	15.9%	$ 6.713	16.2%	$ 5.95	3.0%
Winter Demand Charge	$ 3.109	$ 3.604	$ 0.50	15.9%	$ 3.612	16.2%	$ 3.20	3.0%
Reactive Demand Adjustment	$ 0.7260	$ 0.8434	$ 0.12	16.2%	$ 0.8415	15.9%	$ 0.74619	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Large General Service (LGS)								
LGS - Primary All Electric (One Meter)								
Customer Charge								
0-24 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
25-199 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
200-999 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
1001+kW	$ 863.59	$ 1,001.15	$ 137.56	15.9%	$ 863.59	0.0%	$ 863.59	0.0%
Separately Metered Space Heat	$ 2.32	$ 2.69	$ 0.37	15.9%	$ 2.32	0.0%	$ 2.32	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.08296	$ 0.09617	$ 0.01	15.9%	$ 0.09616	15.9%	$ 0.08527	2.8%
Summer Energy Rate 2nd Block	$ 0.05930	$ 0.06875	$ 0.01	15.9%	$ 0.06874	15.9%	$ 0.06095	2.8%
Summer Energy Rate 3rd Block	$ 0.04160	$ 0.04823	$ 0.01	15.9%	$ 0.04822	15.9%	$ 0.04276	2.8%
Winter Energy Rate 1st Block	$ 0.06991	$ 0.08105	$ 0.01	15.9%	$ 0.08104	15.9%	$ 0.07185	2.8%
Winter Energy Rate 2nd Block	$ 0.03934	$ 0.04561	$ 0.01	15.9%	$ 0.04560	15.9%	$ 0.04043	2.8%
Winter Energy Rate 3rd Block	$ 0.03080	$ 0.03571	$ 0.00	15.9%	$ 0.03570	15.9%	$ 0.03166	2.8%
Facilities Charge	$ 2.40	$ 2.78	$ 0.38	15.9%	$ 2.78	15.9%	$ 2.47	2.8%
Summer Demand Charge	$ 5.65	$ 6.55	$ 0.90	15.9%	$ 6.55	15.9%	$ 5.80	2.8%
Winter Demand Charge	$ 2.81	$ 3.26	$ 0.45	15.9%	$ 3.26	15.9%	$ 2.89	2.8%
Reactive Demand Adjustment	$ 0.7260	$ 0.8434	$ 0.12	16.2%	$ 0.8415	15.9%	$ 0.74619	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
LGS - Secondary All Electric (One Meter)								
Customer Charge								
0-24 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
25-199 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
200-999 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
1001+kW	$ 863.59	$ 1,001.15	$ 137.56	15.9%	$ 863.59	0.0%	$ 863.59	0.0%
Separately Metered Space Heat	$ 2.32	$ 2.69	$ 0.37	15.9%	$ 2.32	0.0%	$ 2.32	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.08486	$ 0.09838	$ 0.01	15.9%	$ 0.09837	15.9%	$ 0.08722	2.8%
Summer Energy Rate 2nd Block	$ 0.06075	$ 0.07043	$ 0.01	15.9%	$ 0.07042	15.9%	$ 0.06244	2.8%
Summer Energy Rate 3rd Block	$ 0.04260	$ 0.04939	$ 0.01	15.9%	$ 0.04938	15.9%	$ 0.04378	2.8%
Winter Energy Rate 1st Block	$ 0.07141	$ 0.08278	$ 0.01	15.9%	$ 0.08278	15.9%	$ 0.07340	2.8%
Winter Energy Rate 2nd Block	$ 0.04023	$ 0.04664	$ 0.01	15.9%	$ 0.04663	15.9%	$ 0.04135	2.8%
Winter Energy Rate 3rd Block	$ 0.03140	$ 0.03640	$ 0.01	15.9%	$ 0.03640	15.9%	$ 0.03227	2.8%
Facilities Charge	$ 2.69	$ 3.36	$ 0.46	15.9%	$ 3.36	16.2%	$ 2.982	3.0%
Summer Demand Charge	$ 5.78	$ 6.70	$ 0.92	15.9%	$ 6.71	16.2%	$ 5.95	3.0%
Winter Demand Charge	$ 2.88	$ 3.34	$ 0.46	15.9%	$ 3.34	15.9%	$ 2.96	2.8%
Reactive Demand Adjustment	$ 0.7260	$ 0.8434	$ 0.12	16.2%	$ 0.8415	15.9%	$ 0.74619	2.8%
LGS - Secondary Space Heat (Two Meter)								
Customer Charge								
0-24 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
25-199 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
200-999 kW	$ 101.15	$ 117.26	$ 16.11	15.9%	$ 101.15	0.0%	$ 101.15	0.0%
1001+kW	$ 863.59	$ 1,001.15	$ 137.56	15.9%	$ 863.59	0.0%	$ 863.59	0.0%
Separately Metered Space Heat	$ 2.32	$ 2.69	$ 0.37	15.9%	$ 2.32	0.0%	$ 2.32	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.08486	$ 0.09838	$ 0.01	15.9%	$ 0.09859	16.2%	$ 0.08743	3.0%
Summer Energy Rate 2nd Block	$ 0.06075	$ 0.07043	$ 0.01	15.9%	$ 0.07058	16.2%	$ 0.06259	3.0%
Summer Energy Rate 3rd Block	$ 0.04260	$ 0.04939	$ 0.01	15.9%	$ 0.04949	16.2%	$ 0.04389	3.0%
Winter Energy Rate 1st Block	$ 0.07798	$ 0.09040	$ 0.01	15.9%	$ 0.09060	16.2%	$ 0.08035	3.0%
Winter Energy Rate 2nd Block	$ 0.04670	$ 0.05414	$ 0.01	15.9%	$ 0.05426	16.2%	$ 0.04812	3.0%
Winter Energy Rate 3rd Block	$ 0.03580	$ 0.04150	$ 0.01	15.9%	$ 0.04159	16.2%	$ 0.03689	3.0%
Facilities Charge	$ 2.89	$ 3.36	$ 0.46	15.9%	$ 3.36	16.2%	$ 2.98	3.0%
Summer Demand Charge	$ 5.78	$ 6.70	$ 0.92	15.9%	$ 6.71	16.2%	$ 5.95	3.0%
Winter Demand Charge	$ 3.11	$ 3.60	$ 0.50	15.9%	$ 3.61	16.2%	$ 3.20	3.0%
Separately Metered Space Heat	$ 0.0525	$ 0.0364	$ (0.02)	-30.6%	$ 0.04159	-20.7%	$ 0.0369	-29.7%
Reactive Demand Adjustment	$ 0.7260	$ 0.8434	$ 0.12	16.2%	$ 0.8415	15.9%	$ 0.7462	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description		Company's Present Rates		Company's Proposed Rates		Increase $	Increase %		Alternative Rates at Company's Revenue Requirement	Increase %		Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Large Power Service - LPS													
LPS - Primary													
Customer Charge	$	961.50	$	1,110.63	$	149.13	15.5%	$	961.50	0.0%	$	961.50	0.0%
Energy Charge													
Summer Energy Rate 1st Block	$	0.07643	$	0.08828	$	0.01	15.5%	$	0.08851	15.8%	$	0.07854	2.8%
Summer Energy Rate 2nd Block	$	0.04800	$	0.05544	$	0.01	15.5%	$	0.05559	15.8%	$	0.04933	2.8%
Summer Energy Rate 3rd Block	$	0.02507	$	0.02896	$	0.00	15.5%	$	0.02903	15.8%	$	0.02576	2.8%
Winter Energy Rate 1st Block	$	0.06480	$	0.07485	$	0.01	15.5%	$	0.07504	15.8%	$	0.06659	2.8%
Winter Energy Rate 2nd Block	$	0.04365	$	0.05042	$	0.01	15.5%	$	0.05055	15.8%	$	0.04486	2.8%
Winter Energy Rate 3rd Block	$	0.02484	$	0.02869	$	0.00	15.5%	$	0.02877	15.8%	$	0.02553	2.8%
Facilities Charge	$	2.67	$	3.08	$	0.41	15.5%	$	3.09	15.8%	$	2.74	2.8%
Summer Demand Charge													
First 2500 kW	$	12.21	$	14.10	$	1.89	15.5%	$	14.14	15.8%	$	12.54	2.8%
Next 2500 kW	$	9.77	$	11.28	$	1.52	15.5%	$	11.31	15.8%	$	10.03	2.8%
Next 2500 kW	$	8.18	$	9.45	$	1.27	15.5%	$	9.47	15.8%	$	8.40	2.8%
Over 7500 kW	$	5.97	$	6.90	$	0.93	15.5%	$	6.92	15.8%	$	6.14	2.8%
Winter Demand Charge													
First 2500 kW	$	8.30	$	9.58	$	1.29	15.5%	$	9.61	15.8%	$	8.53	2.8%
Next 2500 kW	$	6.48	$	7.48	$	1.00	15.5%	$	7.50	15.8%	$	6.65	2.8%
Next 2500 kW	$	5.71	$	6.60	$	0.89	15.5%	$	6.61	15.8%	$	5.87	2.8%
Over 7500 kW	$	4.40	$	5.08	$	0.68	15.5%	$	5.09	15.8%	$	4.52	2.8%
Reactive Demand Adjustment	$	0.8080	$	0.935	$	0.13	15.7%	$	0.936	15.8%	$	0.83030	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
LPS - Secondary								
Customer Charge	$ 961.50	$ 1,110.63	$ 149.13	15.5%	$ 961.50	0.0%	$ 961.50	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.07822	$ 0.09035	$ 0.01	15.5%	$ 0.09065	15.9%	$ 0.08039	2.8%
Summer Energy Rate 2nd Block	$ 0.04911	$ 0.05673	$ 0.01	15.5%	$ 0.05691	15.9%	$ 0.05047	2.8%
Summer Energy Rate 3rd Block	$ 0.02566	$ 0.02964	$ 0.00	15.5%	$ 0.02974	15.9%	$ 0.02637	2.8%
Winter Energy Rate 1st Block	$ 0.06631	$ 0.07659	$ 0.01	15.5%	$ 0.07685	15.9%	$ 0.06815	2.8%
Winter Energy Rate 2nd Block	$ 0.04468	$ 0.05161	$ 0.01	15.5%	$ 0.05178	15.9%	$ 0.04592	2.8%
Winter Energy Rate 3rd Block	$ 0.02541	$ 0.02935	$ 0.00	15.5%	$ 0.02945	15.9%	$ 0.02612	2.8%
Facilities Charge	$ 3.22	$ 3.72	$ 0.50	15.5%	$ 3.73	15.9%	$ 3.31	2.8%
Summer Demand Charge								
First 2500 kW	$ 12.49	$ 14.43	$ 1.94	15.5%	$ 14.48	15.9%	$ 12.84	2.8%
Next 2500 kW	$ 9.99	$ 11.54	$ 1.55	15.5%	$ 11.58	15.9%	$ 10.27	2.8%
Next 2500 kW	$ 8.37	$ 9.67	$ 1.30	15.5%	$ 9.70	15.9%	$ 8.60	2.8%
Over 7500 kW	$ 6.11	$ 7.06	$ 0.95	15.5%	$ 7.08	15.9%	$ 6.28	2.8%
Winter Demand Charge								
First 2500 kW	$ 8.49	$ 9.81	$ 1.32	15.5%	$ 9.84	15.9%	$ 8.73	2.8%
Next 2500 kW	$ 6.63	$ 7.65	$ 1.03	15.5%	$ 7.68	15.9%	$ 6.81	2.8%
Next 2500 kW	$ 5.85	$ 6.75	$ 0.91	15.5%	$ 6.78	15.9%	$ 6.01	2.8%
Over 7500 kW	$ 4.50	$ 5.20	$ 0.70	15.5%	$ 5.22	15.9%	$ 4.62	2.8%
Reactive Demand Adjustment	$ 0.8080	$ 0.9347	$ 0.13	15.7%	$ 0.9357	15.8%	$ 0.8303	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description		Company's Present Rates		Company's Proposed Rates	Increase			Alternative Rates at Company's Revenue Requirement		Increase %		Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
						$	%						
LPS - Substation													
Customer Charge	$	961.50	$	1,110.63	$	149.13	15.5%	$	961.50	0.0%	$	961.50	0.0%
Energy Charge													
Summer Energy Rate 1st Block	$	0.07554	$	0.08726	$	0.01	15.5%	$	0.08743	15.7%	$	0.07762	2.7%
Summer Energy Rate 2nd Block	$	0.04744	$	0.05480	$	0.01	15.5%	$	0.05491	15.7%	$	0.04874	2.7%
Summer Energy Rate 3rd Block	$	0.02477	$	0.02861	$	0.004	15.5%	$	0.02867	15.7%	$	0.02545	2.7%
Winter Energy Rate 1st Block	$	0.06405	$	0.07398	$	0.01	15.5%	$	0.07413	15.7%	$	0.06581	2.7%
Winter Energy Rate 2nd Block	$	0.04314	$	0.04983	$	0.01	15.5%	$	0.04993	15.7%	$	0.04433	2.7%
Winter Energy Rate 3rd Block	$	0.02454	$	0.02835	$	0.004	15.5%	$	0.02840	15.7%	$	0.02521	2.7%
Facilities Charge	$	0.8060	$	0.9310	$	0.13	15.5%	$	0.9300	15.4%	$	0.8282	2.7%
Summer Demand Charge													
First 2500 kW	$	12.06	$	13.93	$	1.87	15.5%	$	13.96	15.7%	$	12.39	2.7%
Next 2500 kW	$	9.65	$	11.14	$	1.50	15.5%	$	11.17	15.7%	$	9.91	2.7%
Next 2500 kW	$	8.08	$	9.34	$	1.25	15.5%	$	9.35	15.7%	$	8.30	2.7%
Over 7500 kW	$	5.90	$	6.82	$	0.92	15.5%	$	6.83	15.7%	$	6.06	2.7%
Winter Demand Charge													
First 2500 kW	$	8.20	$	9.47	$	1.27	15.5%	$	9.49	15.7%	$	8.42	2.7%
Next 2500 kW	$	6.40	$	7.39	$	0.99	15.5%	$	7.41	15.7%	$	6.57	2.7%
Next 2500 kW	$	5.65	$	6.52	$	0.88	15.5%	$	6.53	15.7%	$	5.80	2.7%
Over 7500 kW	$	4.35	$	5.02	$	0.67	15.5%	$	5.03	15.7%	$	4.47	2.7%
Reactive Demand Adjustment	$	0.8080	$	0.9347	$	0.1267	15.7%	$	0.936	15.8%	$	0.83030	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
LPS - Transmission								
Customer Charge	$ 961.50	$ 1,110.63	$ 149.13	15.5%	$ 961.50	0.0%	$ 961.50	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.07487	$ 0.08648	$ 0.012	15.5%	0.08668	15.8%	$ 0.07693	2.8%
Summer Energy Rate 2nd Block	$ 0.04701	$ 0.05430	$ 0.007	15.5%	0.05442	15.8%	$ 0.04831	2.8%
Summer Energy Rate 3rd Block	$ 0.02456	$ 0.02837	$ 0.004	15.5%	0.02843	15.8%	$ 0.02524	2.8%
Winter Energy Rate 1st Block	$ 0.06346	$ 0.07330	$ 0.010	15.5%	0.07347	15.8%	$ 0.06521	2.8%
Winter Energy Rate 2nd Block	$ 0.04275	$ 0.04938	$ 0.007	15.5%	0.04949	15.8%	$ 0.04393	2.8%
Winter Energy Rate 3rd Block	$ 0.02431	$ 0.02808	$ 0.004	15.5%	0.02814	15.8%	$ 0.02498	2.8%
Summer Demand Charge								
First 2500 kW	$ 11.956	$ 13.810	$ 1.85	15.5%	$ 13.84	15.8%	$ 12.29	2.8%
Next 2500 kW	$ 9.562	$ 11.045	$ 1.48	15.5%	$ 11.07	15.8%	$ 9.83	2.8%
Next 2500 kW	$ 8.008	$ 9.250	$ 1.24	15.5%	$ 9.27	15.8%	$ 8.23	2.8%
Over 7500 kW	$ 5.848	$ 6.755	$ 0.91	15.5%	$ 6.77	15.8%	$ 6.01	2.8%
Winter Demand Charge								
First 2500 kW	$ 8.125	$ 9.385	$ 1.26	15.5%	$ 9.41	15.8%	$ 8.35	2.8%
Next 2500 kW	$ 6.342	$ 7.326	$ 0.98	15.5%	$ 7.34	15.8%	$ 6.52	2.8%
Next 2500 kW	$ 5.595	$ 6.463	$ 0.87	15.5%	$ 6.48	15.8%	$ 5.75	2.8%
Over 7500 kW	$ 4.307	$ 4.975	$ 0.67	15.5%	$ 4.99	15.8%	$ 4.43	2.8%
Reactive Demand Adjustment	$ 0.8080	$ 0.9347	$ 0.1267	15.7%	$ 0.9354	15.8%	$ 0.8303	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
LPS - Transmission Off Peak								
Customer Charge	$ 961.50	$ 1,110.63	$ 149.13	15.5%	$ 961.50	0.0%	$ 961.50	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.07487	$ 0.08648	$ 0.01	15.5%	$ 0.08668	15.8%	$ 0.07693	2.8%
Summer Energy Rate 2nd Block	$ 0.04701	$ 0.05430	$ 0.01	15.5%	$ 0.05442	15.8%	$ 0.04831	2.8%
Summer Energy Rate 3rd Block	$ 0.02456	$ 0.02837	$ 0.00	15.5%	$ 0.02843	15.8%	$ 0.02524	2.8%
Winter Energy Rate 1st Block	$ 0.06346	$ 0.07330	$ 0.01	15.5%	$ 0.07347	15.8%	$ 0.06521	2.8%
Winter Energy Rate 2nd Block	$ 0.04275	$ 0.04938	$ 0.01	15.5%	$ 0.04949	15.8%	$ 0.04393	2.8%
Winter Energy Rate 3rd Block	$ 0.02431	$ 0.02808	$ 0.00	15.5%	$ 0.02814	15.8%	$ 0.02498	2.8%
Summer Demand Charge								
First 2500 kW	$ 11.956	$ 13.810	$ 1.85	15.5%	$ 13.84	15.8%	$ 12.29	2.8%
Next 2500 kW	$ 9.562	$ 11.045	$ 1.48	15.5%	$ 11.07	15.8%	$ 9.83	2.8%
Next 2500 kW	$ 8.008	$ 9.250	$ 1.24	15.5%	$ 9.27	15.8%	$ 8.23	2.8%
Over 7500 kW	$ 5.848	$ 6.755	$ 0.91	15.5%	$ 6.77	15.8%	$ 6.01	2.8%
Winter Demand Charge								
First 2500 kW	$ 8.125	$ 9.385	$ 1.26	15.5%	$ 9.406	15.8%	$ 8.35	2.8%
Next 2500 kW	$ 6.342	$ 7.326	$ 0.98	15.5%	$ 7.342	15.8%	$ 6.52	2.8%
Next 2500 kW	$ 5.595	$ 6.463	$ 0.87	15.5%	$ 6.477	15.8%	$ 5.75	2.8%
Over 7500 kW	$ 4.307	$ 4.975	$ 0.67	15.5%	$ 4.986	15.8%	$ 4.43	2.8%
Reactive Demand Adjustment	$ 0.8080	$ 0.9347	$ 0.13	15.7%	$ 0.936	15.8%	$ 0.83030	2.8%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
LPS - Primary Off Peak								
Customer Charge	$ 961.50	$ 1,110.63	$ 149.13	15.5%	$ 961.50	0.0%	$ 961.50	0.0%
Energy Charge								
Summer Energy Rate 1st Block	$ 0.07643	$ 0.08828	$ 0.01	15.5%	$ 0.08851	15.8%	$ 0.07854	2.8%
Summer Energy Rate 2nd Block	$ 0.04800	$ 0.05544	$ 0.01	15.5%	$ 0.05559	15.8%	$ 0.04933	2.8%
Summer Energy Rate 3rd Block	$ 0.02507	$ 0.02896	$ 0.00	15.5%	$ 0.02903	15.8%	$ 0.02576	2.8%
Winter Energy Rate 1st Block	$ 0.06480	$ 0.07485	$ 0.01	15.5%	$ 0.07504	15.8%	$ 0.06659	2.8%
Winter Energy Rate 2nd Block	$ 0.04365	$ 0.05042	$ 0.01	15.5%	$ 0.05055	15.8%	$ 0.04486	2.8%
Winter Energy Rate 3rd Block	$ 0.02484	$ 0.02869	$ 0.00	15.5%	$ 0.02877	15.8%	$ 0.02553	2.8%
Facilities Charge	$ 2.669	$ 3.083	$ 0.41	15.5%	$ 3.091	15.8%	$ 2.74	2.8%
Summer Demand Charge								
First 2500 kW	$ 12.206	$ 14.099	$ 1.89	15.5%	$ 14.135	15.8%	$ 12.54	2.8%
Next 2500 kW	$ 9.765	$ 11.280	$ 1.52	15.5%	$ 11.308	15.8%	$ 10.03	2.8%
Next 2500 kW	$ 8.179	$ 9.448	$ 1.27	15.5%	$ 9.472	15.8%	$ 8.40	2.8%
Over 7500 kW	$ 5.972	$ 6.898	$ 0.93	15.5%	$ 6.916	15.8%	$ 6.14	2.8%
Winter Demand Charge								
First 2500 kW	$ 8.296	$ 9.583	$ 1.29	15.5%	$ 9.607	15.8%	$ 8.53	2.8%
Next 2500 kW	$ 6.476	$ 7.480	$ 1.00	15.5%	$ 7.500	15.8%	$ 6.65	2.8%
Next 2500 kW	$ 5.712	$ 6.598	$ 0.89	15.5%	$ 6.615	15.8%	$ 5.87	2.8%
Over 7500 kW	$ 4.399	$ 5.081	$ 0.68	15.5%	$ 5.094	15.8%	$ 4.52	2.8%
Reactive Demand Adjustment	$ 0.8030	$ 0.9347	$ 0.13	15.7%	$ 0.9357	15.8%	$ 0.83030	2.8%
Private Unmetered Lighting Service (AL)								
Base Charge								
5800 Lumen High Pressure Sodium	$ 20.63	$ 23.88	$ 3.25	15.8%	$ 23.87	15.7%	$ 21.20	2.7%
8600 Lumen Mercury Vapor	$ 21.69	$ 25.11	$ 3.42	15.8%	$ 25.10	15.7%	$ 22.29	2.7%
16000 Lumen High Pressure Sodium	$ 23.62	$ 27.34	$ 3.72	15.7%	$ 27.33	15.7%	$ 24.27	2.7%
22500 Lumen Mercury Vapor	$ 26.55	$ 30.74	$ 4.19	15.8%	$ 30.72	15.7%	$ 27.28	2.7%
22500 Lumen Mercury Vapor	$ 26.55	$ 30.74	$ 4.19	15.8%	$ 30.72	15.7%	$ 27.28	2.7%
27500 Lumen High Pressure Sodium	$ 25.11	$ 29.07	$ 3.96	15.8%	$ 29.06	15.7%	$ 25.80	2.7%
50000 Lumen High Pressure Sodium	$ 27.40	$ 31.72	$ 4.32	15.8%	$ 31.71	15.7%	$ 28.15	2.7%
63000 Lumen Mercury Vapor	$ 34.50	$ 39.94	$ 5.44	15.8%	$ 39.92	15.7%	$ 35.45	2.7%
Additional Charges								
Each 30-foot ornamental steel pole installed	$ 6.34	$ 7.34	$ 1.00	15.8%	$ 7.336	15.7%	$ 6.51	2.7%
Each 35-foot ornamental steel pole installed	$ 7.23	$ 8.37	$ 1.14	15.8%	$ 8.366	15.7%	$ 7.43	2.7%
Each 30-foot wood pole installed	$ 4.85	$ 5.61	$ 0.76	15.7%	$ 5.612	15.7%	$ 4.98	2.7%
Each 35-foot wood pole installed	$ 5.30	$ 6.14	$ 0.84	15.8%	$ 6.133	15.7%	$ 5.45	2.7%
Each overhead span of circuit installed	$ 3.55	$ 4.11	$ 0.56	15.8%	$ 4.108	15.7%	$ 3.65	2.7%
Underground lighting unit (per month)	$ 2.71	$ 3.14	$ 0.43	15.9%	$ 3.136	15.7%	$ 2.78	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Municipal Street Lighting Service (ML)								
Mercury Vapor and High Pressure Sodium Vapor								
8600 Lumen Mercury Vapor	$ 236.88	$ 274.20	$ 37.32	15.8%	$ 274.08	15.7%	$ 243.36	2.7%
8600 Lumen Mercury Vapor - Twin	$ 473.76	$ 548.40	$ 74.64	15.8%	$ 548.16	15.7%	$ 486.72	2.7%
12,100 Lumen Mercury Vapor	$ 265.68	$ 307.56	$ 41.88	15.8%	$ 307.44	15.7%	$ 273.00	2.8%
12,100 Lumen Mercury Vapor - Twin	$ 531.36	$ 615.12	$ 83.76	15.8%	$ 614.88	15.7%	$ 546.00	2.8%
22,500 Lumen Mercury Vapor	$ 289.68	$ 335.40	$ 45.72	15.8%	$ 335.16	15.7%	$ 297.60	2.7%
22,500 Lumen Mercury Vapor - Twin	$ 579.36	$ 670.80	$ 91.44	15.8%	$ 670.32	15.7%	$ 595.20	2.7%
9500 Lumen High Pressure Sodium	$ 231.24	$ 267.72	$ 36.48	15.8%	$ 267.60	15.7%	$ 237.60	2.8%
9500 Lumen High Pressure Sodium - Twin	$ 462.48	$ 535.44	$ 72.96	15.8%	$ 535.20	15.7%	$ 475.20	2.8%
16,000 Lumen High Pressure Sodium	$ 257.64	$ 298.32	$ 40.68	15.8%	$ 298.08	15.7%	$ 264.72	2.7%
16,000 Lumen High Pressure Sodium - Twin	$ 515.28	$ 596.64	$ 81.36	15.8%	$ 596.16	15.7%	$ 529.44	2.7%
27,500 Lumen High Pressure Sodium	$ 273.84	$ 317.04	$ 43.20	15.8%	$ 316.92	15.7%	$ 281.40	2.8%
27,500 Lumen High Pressure Sodium - Twin	$ 547.68	$ 634.08	$ 86.40	15.8%	$ 633.84	15.7%	$ 562.80	2.8%
50,000 Lumen High Pressure Sodium	$ 298.68	$ 345.84	$ 47.16	15.8%	$ 345.60	15.7%	$ 306.84	2.7%
50,000 Lumen High Pressure Sodium - Twin	$ 597.36	$ 691.68	$ 94.32	15.8%	$ 691.20	15.7%	$ 613.68	2.7%
Optional Equipment								
Ornamental Steel Pole	$ 16.08	$ 18.60	$ 2.52	15.7%	$ 18.60	15.7%	$ 16.56	3.0%
Aluminum Pole	$ 40.44	$ 46.80	$ 6.36	15.7%	$ 46.80	15.7%	$ 41.52	2.7%
Underground Svc Under Sod	$ 68.04	$ 78.72	$ 10.68	15.7%	$ 78.72	15.7%	$ 69.96	2.8%
Underground Svc Under Concrete	$ 259.80	$ 300.72	$ 40.92	15.8%	$ 300.60	15.7%	$ 266.88	2.7%
Breakaway Base	$ 37.20	$ 43.08	$ 5.88	15.8%	$ 43.08	15.8%	$ 38.28	2.9%
Energy for Customer-Owned Lighting	$ 0.07	$ 0.08	$ 0.01	15.8%	$ 0.08	15.7%	$ 0.07	2.7%
Code CX (single) (799 kwh per year)	$ 56.73	$ 65.68	$ 8.95	15.8%	$ 65.64	15.7%	$ 58.29	2.7%
Code TCX (twin) (1598 kwh per year)	$ 113.46	$ 131.35	$ 17.89	15.8%	$ 131.28	15.7%	$ 116.57	2.7%
Energy for Customer-Owned Lighting	$ 0.07	$ 0.08	$ 0.01	15.8%	$ 0.08	15.7%	$ 0.07	2.7%
9500 Lumen High Pressure Sodium	$ 136.20	$ 157.68	$ 21.48	15.8%	$ 157.56	15.7%	$ 139.92	2.7%
16000 Lumen High Pressure Sodium	$ 225.60	$ 261.12	$ 35.52	15.7%	$ 261.00	15.7%	$ 231.84	2.8%
8600 Lumen Mercury Vapor	$ 236.88	$ 274.20	$ 37.32	15.8%	$ 274.08	15.7%	$ 243.36	2.7%
8600 Lumen Mercury Vapor - Twin	$ 473.76	$ 548.40	$ 74.64	15.8%	$ 548.16	15.7%	$ 486.72	2.7%
12100 Lumen Mercury Vapor	$ 265.68	$ 307.56	$ 41.88	15.8%	$ 307.44	15.7%	$ 273.00	2.8%
12100 Lumen Mercury Vapor - Twin	$ 531.36	$ 615.12	$ 83.76	15.8%	$ 614.88	15.7%	$ 546.00	2.8%
22500 Lumen Mercury Vapor	$ 289.68	$ 335.40	$ 45.72	15.8%	$ 335.16	15.7%	$ 297.60	2.7%
22500 Lumen Mercury Vapor - Twin	$ 579.36	$ 670.80	$ 91.44	15.8%	$ 670.32	15.7%	$ 595.20	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description		Company's Present Rates		Company's Proposed Rates		Increase $	Increase %		Alternative Rates at Company's Revenue Requirement	Increase %		Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Municipal Street Lighting Service (ML)													
9500 Lumen High Pressure Sodium	$	231.24	$	267.72	$	36.48	15.8%	$	267.60	15.7%	$	237.60	2.8%
9500 Lumen High Pressure Sodium - Twin	$	462.48	$	535.44	$	72.96	15.8%	$	535.20	15.7%	$	475.20	2.8%
16000 Lumen High Pressure Sodium	$	257.64	$	298.32	$	40.68	15.8%	$	298.08	15.7%	$	264.72	2.7%
16000 Lumen High Pressure Sodium - Twin	$	515.28	$	596.64	$	81.36	15.8%	$	596.16	15.7%	$	529.44	2.7%
27500 Lumen High Pressure Sodium	$	273.84	$	317.04	$	43.20	15.8%	$	316.92	15.7%	$	281.40	2.8%
27500 Lumen High Pressure Sodium - Twin	$	547.68	$	634.08	$	86.40	15.8%	$	633.84	15.7%	$	562.80	2.8%
50000 Lumen High Pressure Sodium	$	298.68	$	345.84	$	47.16	15.8%	$	345.60	15.7%	$	306.84	2.7%
50000 Lumen High Pressure Sodium - Twin	$	597.36	$	691.68	$	94.32	15.8%	$	691.20	15.7%	$	613.68	2.7%
Ornamental Steel Pole	$	16.08	$	18.60	$	2.52	15.7%	$	18.60	15.7%	$	16.56	3.0%
Aluminum Pole	$	40.44	$	46.80	$	6.36	15.7%	$	46.80	15.7%	$	41.52	2.7%
Underground Service extension, under sod	$	68.04	$	78.72	$	10.68	15.7%	$	78.72	15.7%	$	69.96	2.8%
Underground Service extension, under concrete	$	259.80	$	300.72	$	40.92	15.8%	$	300.60	15.7%	$	266.88	2.7%
Breakaway Base	$	37.20	$	43.08	$	5.88	15.8%	$	43.08	15.8%	$	38.28	2.9%
8600 Lumen - Limited Maintenance	$	115.20	$	133.32	$	18.12	15.7%	$	133.32	15.7%	$	118.32	2.7%
22500 Lumen - Limited Maintenance	$	250.56	$	290.04	$	39.48	15.8%	$	289.92	15.7%	$	257.40	2.7%
9500 Lumen - Limited Maintenance	$	115.20	$	133.32	$	18.12	15.7%	$	133.32	15.7%	$	118.32	2.7%
27500 Lumen - Limited Maintenance	$	250.56	$	290.04	$	39.48	15.8%	$	289.92	15.7%	$	257.40	2.7%
Light Emitting Diode (LED)													
Small LED (≤ 7000 lumens) - Single	$	231.24	$	267.72	$	36.48	15.8%	$	267.60	15.7%	$	237.60	2.8%
Small LED (≤ 7000 lumens) - Twin	$	462.48	$	535.44	$	72.96	15.8%	$	535.20	15.7%	$	475.20	2.8%
Large LED (> 7000 lumens) - Single	$	257.64	$	298.32	$	40.68	15.8%	$	298.08	15.7%	$	264.72	2.7%
Large LED (> 7000 lumens) - Twin	$	515.28	$	596.64	$	81.36	15.8%	$	596.16	15.7%	$	529.44	2.7%
Optional Equipment													
Ornamental steel pole	$	16.08	$	18.60	$	2.52	15.7%	$	18.60	15.7%	$	16.56	3.0%
Aluminum pole	$	40.44	$	46.80	$	6.36	15.7%	$	46.80	15.7%	$	41.52	2.7%
Underground service extension - under sod	$	68.04	$	78.72	$	10.68	15.7%	$	78.72	15.7%	$	69.96	2.8%
Underground service extension - under concrete	$	259.80	$	300.72	$	40.92	15.8%	$	300.60	15.7%	$	266.88	2.7%
Breakaway base	$	37.20	$	43.08	$	5.88	15.8%	$	43.04	15.7%	$	38.22	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Off-Peak Lighting Service (OLS)								
Nominal Rating in Watts:								
1 - 99								
Total Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%
100 - 149								
First 100 Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%
Excess over 100 Watts X MBH X BLF / 1000	$ 0.06694	$ 0.07750	$ 0.01	15.8%	$ 0.07746	15.7%	$ 0.06878	2.7%
150 - 249								
First 100 Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%
Next 50 Watts X MBH X BLF / 1001	$ 0.06694	$ 0.07750	$ 0.01	15.8%	$ 0.07746	15.7%	$ 0.06878	2.7%
Excess over 150 Watts X MBH X BLF / 1000	$ 0.06462	$ 0.07481	$ 0.01	15.8%	$ 0.07477	15.7%	$ 0.06639	2.7%
250 - 399								
First 100 Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%
Next 150 Watts X MBH X BLF / 1001	$ 0.06462	$ 0.07481	$ 0.01	15.8%	$ 0.07477	15.7%	$ 0.06639	2.7%
Excess over 250 Watts X MBH X BLF / 1000	$ 0.05885	$ 0.06813	$ 0.01	15.8%	$ 0.06810	15.7%	$ 0.06047	2.8%
400 and Above								
First 100 Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%
Next 300 Watts X MBH X BLF / 1001	$ 0.05885	$ 0.06813	$ 0.01	15.8%	$ 0.06810	15.7%	$ 0.06047	2.8%
Excess over 400 Watts X MBH X BLF / 1000	$ 0.05885	$ 0.06813	$ 0.01	15.8%	$ 0.06810	15.7%	$ 0.06047	2.8%
All Wattages								
Total Watts X MBH X BLF / 1000	$ 0.07155	$ 0.08283	$ 0.01	15.8%	$ 0.08279	15.7%	$ 0.07351	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Municipal Traffic Control Signal Service (TR)								
Basic Installation								
Individual Control	$ 174.73	$ 202.29	$ 27.56	15.8%	$ 202.18	15.7%	$ 179.53	2.7%
Suspension Control[1]	$ 80.21	$ 92.86	$ 12.65	15.8%	$ 92.81	15.7%	$ 82.41	2.7%
1-Way, 1-Light Signal Unit	$ 41.16	$ 47.65	$ 6.49	15.8%	$ 47.63	15.7%	$ 42.29	2.7%
4-Way, 1-Light Signal Unit - Suspension	$ 48.72	$ 56.40	$ 7.68	15.8%	$ 56.37	15.7%	$ 50.06	2.7%
Pedestrian Push Button Control	$ 146.24	$ 169.30	$ 23.06	15.8%	$ 169.22	15.7%	$ 150.25	2.7%
Coordinated Multi-Dial Control[1]	$ 257.86	$ 298.53	$ 40.67	15.8%	$ 298.37	15.7%	$ 264.94	2.7%
Multi-Phase Electronic Control	$ 421.97	$ 488.52	$ 66.55	15.8%	$ 488.27	15.7%	$ 433.55	2.7%
Supplemental Equipment								
Multi-Dial Controller[1]	$ 18.04	$ 20.88	$ 2.84	15.7%	$ 20.87	15.7%	$ 18.54	2.7%
Coordinating Cable Connection[1]	$ 20.51	$ 23.74	$ 3.23	15.7%	$ 23.73	15.7%	$ 21.07	2.7%
Excess Coordinating Cable - Under sod[1]	$ 0.15	$ 0.17	$ 0.02	13.3%	$ 0.17	15.7%	$ 0.15	2.7%
Excess Coordinating Cable - Under concrete[1]	$ 0.45	$ 0.52	$ 0.07	15.6%	$ 0.52	15.7%	$ 0.46	2.7%
3-Light Signal Unit	$ 24.86	$ 28.78	$ 3.92	15.8%	$ 28.77	15.7%	$ 25.54	2.7%
2-Light Signal Unit	$ 23.92	$ 27.69	$ 3.77	15.8%	$ 27.68	15.7%	$ 24.58	2.7%
1-Light Signal Unit	$ 7.49	$ 8.67	$ 1.18	15.8%	$ 8.67	15.7%	$ 7.70	2.7%
Pedestrian Control Equipment-Push Buttons	$ 3.34	$ 3.87	$ 0.53	15.9%	$ 3.86	15.7%	$ 3.43	2.7%
12-Inch Round Lens	$ 6.07	$ 7.03	$ 0.96	15.8%	$ 7.02	15.7%	$ 6.24	2.7%
9-Inch Square Lens	$ 6.87	$ 7.95	$ 1.08	15.7%	$ 7.95	15.7%	$ 7.06	2.7%
Directional Louvre[1]	$ 1.49	$ 1.72	$ 0.23	15.4%	$ 1.72	15.7%	$ 1.53	2.7%
Vehicle - Actuation Unit - Loop Detector-Single	$ 31.10	$ 36.00	$ 4.90	15.8%	$ 35.99	15.7%	$ 31.95	2.7%
Vehicle - Actuation Unit - Loop Detector-Double	$ 49.35	$ 57.13	$ 7.78	15.8%	$ 57.10	15.7%	$ 50.70	2.7%
Flasher Equipment	$ 8.83	$ 10.22	$ 1.39	15.7%	$ 10.22	15.7%	$ 9.07	2.7%
Mast Arm - Style 2	$ 41.33	$ 47.85	$ 6.52	15.8%	$ 47.82	15.7%	$ 42.46	2.7%
Mast Arm - Style 3	$ 40.96	$ 47.42	$ 6.46	15.8%	$ 47.40	15.7%	$ 42.08	2.7%
Back Plate	$ 1.89	$ 2.19	$ 0.30	15.9%	$ 2.19	15.7%	$ 1.94	2.7%
Wood Pole Suspension	$ 19.15	$ 22.17	$ 3.02	15.8%	$ 22.16	15.7%	$ 19.68	2.7%
Steel Pole Suspension[1]	$ 46.22	$ 53.51	$ 7.29	15.8%	$ 53.48	15.7%	$ 47.49	2.7%
Pedestrian Timer[1]	$ 10.85	$ 12.56	$ 1.71	15.8%	$ 12.55	15.7%	$ 11.15	2.7%
Traffic Signal Pole	$ 10.50	$ 12.16	$ 1.66	15.8%	$ 12.15	15.7%	$ 10.79	2.7%

[1] The Company is recommending discontinuation of this rate.

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Two Part Time of Use (TPP)								
Secondary								
Winter On-Peak								
Small General/All Electric	$ 0.04874	$ 0.05643	$ 0.01	15.8%	$ 0.05640	15.7%	$ 0.05008	2.7%
Medium General/All Electric	$ 0.04232	$ 0.04899	$ 0.01	15.8%	$ 0.04897	15.7%	$ 0.04348	2.7%
Large General/All Electric	$ 0.04051	$ 0.04690	$ 0.01	15.8%	$ 0.04687	15.7%	$ 0.04162	2.7%
Large Power	$ 0.03550	$ 0.04110	$ 0.01	15.8%	$ 0.04108	15.7%	$ 0.03647	2.7%
Winter Off-Peak								
Small General/All Electric	$ 0.04206	$ 0.04869	$ 0.01	15.8%	$ 0.04867	15.7%	$ 0.04321	2.7%
Medium General/All Electric	$ 0.03401	$ 0.03937	$ 0.01	15.8%	$ 0.03935	15.7%	$ 0.03494	2.7%
Large General/All Electric	$ 0.03267	$ 0.03782	$ 0.01	15.8%	$ 0.03780	15.7%	$ 0.03357	2.8%
Large Power	$ 0.02982	$ 0.03452	$ 0.00	15.8%	$ 0.03451	15.7%	$ 0.03064	2.7%
Summer On-Peak								
Small General/All Electric	$ 0.12588	$ 0.14573	$ 0.02	15.8%	$ 0.14566	15.7%	$ 0.12934	2.7%
Medium General/All Electric	$ 0.11373	$ 0.13167	$ 0.02	15.8%	$ 0.13160	15.7%	$ 0.11685	2.7%
Large General/All Electric	$ 0.11006	$ 0.12742	$ 0.02	15.8%	$ 0.12735	15.7%	$ 0.11308	2.7%
Large Power	$ 0.10318	$ 0.11945	$ 0.02	15.8%	$ 0.11939	15.7%	$ 0.10601	2.7%
Summer Off-Peak								
Small General/All Electric	$ 0.05402	$ 0.06254	$ 0.01	15.8%	$ 0.06251	15.7%	$ 0.05550	2.7%
Medium General/All Electric	$ 0.04507	$ 0.05218	$ 0.01	15.8%	$ 0.05215	15.7%	$ 0.04631	2.8%
Large General/All Electric	$ 0.04309	$ 0.04989	$ 0.01	15.8%	$ 0.04986	15.7%	$ 0.04427	2.7%
Large Power	$ 0.03833	$ 0.04437	$ 0.01	15.8%	$ 0.04435	15.7%	$ 0.03938	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Two Part Time of Use (TPP)								
Primary								
Winter On-Peak								
Small General/All Electric	$ 0.04728	$ 0.05474	$ 0.01	15.8%	$ 0.05471	15.7%	$ 0.04858	2.7%
Medium General/All Electric	$ 0.04104	$ 0.04751	$ 0.01	15.8%	$ 0.04749	15.7%	$ 0.04217	2.8%
Large General/All Electric	$ 0.03931	$ 0.04551	$ 0.01	15.8%	$ 0.04549	15.7%	$ 0.04039	2.7%
Large Power	$ 0.03443	$ 0.03986	$ 0.01	15.8%	$ 0.03984	15.7%	$ 0.03538	2.8%
Winter Off-Peak								
Small General/All Electric	$ 0.04082	$ 0.04726	$ 0.01	15.8%	$ 0.04723	15.7%	$ 0.04194	2.7%
Medium General/All Electric	$ 0.03300	$ 0.03820	$ 0.01	15.8%	$ 0.03818	15.7%	$ 0.03391	2.8%
Large General/All Electric	$ 0.03170	$ 0.03670	$ 0.01	15.8%	$ 0.03668	15.7%	$ 0.03257	2.7%
Large Power	$ 0.02895	$ 0.03352	$ 0.00	15.8%	$ 0.03350	15.7%	$ 0.02974	2.7%
Summer On-Peak								
Small General/All Electric	$ 0.11621	$ 0.13454	$ 0.02	15.8%	$ 0.13447	15.7%	$ 0.11940	2.7%
Medium General/All Electric	$ 0.10497	$ 0.12152	$ 0.02	15.8%	$ 0.12146	15.7%	$ 0.10785	2.7%
Large General/All Electric	$ 0.10160	$ 0.11762	$ 0.02	15.8%	$ 0.11756	15.7%	$ 0.10439	2.7%
Large Power	$ 0.09523	$ 0.11025	$ 0.02	15.8%	$ 0.11019	15.7%	$ 0.09784	2.7%
Summer Off-Peak								
Small General/All Electric	$ 0.05104	$ 0.05909	$ 0.01	15.8%	$ 0.05906	15.7%	$ 0.05244	2.7%
Medium General/All Electric	$ 0.04260	$ 0.04932	$ 0.01	15.8%	$ 0.04929	15.7%	$ 0.04377	2.7%
Large General/All Electric	$ 0.04072	$ 0.04714	$ 0.01	15.8%	$ 0.04712	15.7%	$ 0.04184	2.8%
Large Power	$ 0.03623	$ 0.04194	$ 0.01	15.8%	$ 0.04192	15.7%	$ 0.03722	2.7%

Comparison of Alternative Rates to Current and Proposed Rates

Description	Company's Present Rates	Company's Proposed Rates	Increase $	Increase %	Alternative Rates at Company's Revenue Requirement	Increase %	Alternative Rates at Staff and OPC Adjusted Revenue Requirement	Increase %
Two Part Time of Use (TPP)								
Substation								
Large Power								
Winter On-Peak	$ 0.03401	$ 0.03937	$ 0.01	15.8%	$ 0.03935	15.7%	$ 0.03494	2.7%
Winter Off-Peak	$ 0.02855	$ 0.03305	$ 0.00	15.8%	$ 0.03304	15.7%	$ 0.02933	2.7%
Summer On-Peak	$ 0.08914	$ 0.10320	$ 0.01	15.8%	$ 0.10315	15.7%	$ 0.09159	2.7%
Summer Off-Peak	$ 0.03575	$ 0.04139	$ 0.01	15.8%	$ 0.04137	15.7%	$ 0.03673	2.7%
Transmission								
Large Power	$ 0.03379	$ 0.03912	$ 0.01	15.8%	$ 0.03910	15.7%	$ 0.03472	2.8%
Winter On-Peak	$ 0.02836	$ 0.03283	$ 0.00	15.8%	$ 0.03282	15.7%	$ 0.02914	2.8%
Winter Off-Peak	$ 0.08883	$ 0.10284	$ 0.01	15.8%	$ 0.10279	15.7%	$ 0.09127	2.7%
Summer On-Peak	$ 0.03552	$ 0.04112	$ 0.01	15.8%	$ 0.04110	15.7%	$ 0.03649	2.7%
Summer Off-Peak								
Program Charge								
SGS and SGA Customers	$ 10.00	$ 11.58	$ 1.58	15.8%	$ 11.57	15.7%	$ 10.27	2.7%
All other Customers	$ 30.00	$ 34.73	$ 4.73	15.8%	$ 34.71	15.7%	$ 30.82	2.7%
Standby Service for Self Generation (SGC)								
SGC								
11 am - 2 pm	$ 0.02839	$ 0.03287	$ 0.004	15.8%	$ 0.03285	15.7%	$ 0.02917	2.7%
2 pm - 6 pm	$ 0.06936	$ 0.08030	$ 0.011	15.8%	$ 0.08026	15.7%	$ 0.07126	2.7%
6 pm - 7 pm	$ 0.02839	$ 0.03287	$ 0.004	15.8%	$ 0.03285	15.7%	$ 0.02917	2.7%
Standby or Breakdown Service (1-SA)[1]								
Demand Charge	$ 13.758	$ 15.928	$ 2.17	15.8%	15.92	15.7%	$ 14.14	2.7%
Energy Charge	$ 0.17039	$ 0.19726	$ 0.03	15.8%	0.20	15.7%	$ 0.17507	2.7%

[1] The Company is proposing to discontinue the rates for Standby or Breakdown Service (1-SA).
Source: Rush Direct Testimony, Schedule TMR-9; Company Workpapers MO RES-RD, MO SGS (SGS-SGA), MO MGS (MGS-MGA), MO LGS (LGS-LGA), MO LPS (LPS-LPA), MO Lighting-TPP Rate Design; Schedule DED-6.