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Witness: David E. Dismukes, Ph.D
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MISSOURI PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY
OF
DAVID E. DISMUKES

EMPIRE DISTRICT ELECTRIC COMPANY
CASE NO. ER-2014-0351

Jefferson City, Missouri
February 11, 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.	))))	Case No. ER-2014-0351

AFFIDAVIT OF DAVID DISMUKES

STATE OF LOUISIANA)
) ss
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 11th day of February, 2015.

Notary Public

My Commission expires at death.

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DIRECT TESTIMONY
OF
DAVID E. DISMUKES

EMPIRE DISTRICT ELECTRIC COMPANY

CASE NO. ER-2014-0351

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 17 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 Model and rate design proposed by the Empire District Electric Company ("Empire" 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.

I have prepared two recommended CCOSS Models which the Commission should consider. The first CCOSS model utilizes the Company's AED12CP allocation method for production plant, correcting the calculation of the excess option of the factor as discussed above. The second Alternative CCOSS model allocates production plant using an Average and Peak ("A&12CP") methodology, using the 12 coincident peaks for the peak portion of the factor.

I recommend that the Commission adopt the Company's proposed CCOSS modified so that instead of using a MSS approach for accounts 364 through 368, NCP allocation at the primary and secondary distribution levels is used. In addition, the allocation of line transformers should be on the basis of a NCP-Secondary allocator rather than the number of customers. Finally, Regulatory Expenses should be allocated using gross retail sales revenue in place of the Company's current composite labor and plant allocator.

Q. PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS.

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 1.10 times 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 Company's proposed increase to the customer charges should be rejected since customers are unable to avoid these charges. It may also have an adverse impact on customers with low usage. Additionally, by moving fixed costs from the volumetric charges to the customer charges, customers may lose the incentive to engage in energy efficiency and conservation measures which is an outcome inconsistent with the Commission's energy conservation goals.

III. CLASS COST OF SERVICE STUDY

A. INTRODUCTION

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY?

A. A class cost of service study ("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 DO COST OF SERVICE STUDIES 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 IN THE COMPANY'S CCOSS.

A. The Company uses three separate allocators to allocate different demand-related cost components: a 12 Coincident Peak Average and Excess Demand ("AED 12CP") allocator; a 12 Coincident Peak Demand ("12CP") allocator; and an allocator derived from maximum non-coincident peak ("NCP") demands at the primary and secondary distribution level.

Q. COULD YOU PLEASE DESCRIBE HOW THE AED ALLOCATOR IS TYPICALLY DETERMINED?

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, is the proportion of total average demand (energy consumption) times the system load factor. First, the average demand is calculated by taking total kWh sales and dividing by the total number of hours in the study period. In this manner average demand is a calculation of the average system demand by rate class throughout the study period. The average demand component is calculated by finding the product of the average demand and the quantity of the load factor.

Excess demand is then calculated by taking the difference between a measure of system peak demand, in the Company's CCOSS 12CP, and average system demand by rate class. The excess component is calculated by multiplying the excess factors 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.

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 AED 12CP ALLOCATOR?

A. Yes. The Company states it is using an AED allocation factor that relies on a 12CP as the peak demand component. However, the calculation method the Company utilizes to calculate the AED 12CP allocator is slightly different than the traditional AED methodology described above. The primary difference between the traditional AED method, and the one used by the Company, is associated with how the excess demand component of the allocator is calculated. The Company's calculation determines the excess demand component for each customer class by multiplying the 12CP system peak demand by the system load factor. This amount is then subtracted from the total 12CP amount to derive the excess demand portion of the calculation. Next, instead of deriving the excess demand component from the difference of the NCP component and average demand (energy consumption divided by hours in the year) for each customer class, the Company allocates the total excess demand component by each class's proportion of NCP. The average demand component is apportioned using each class's energy consumption. These two amounts are then combined to determine the final allocation factors. Unlike the traditional method, the Company does not utilize the load factor or one minus the load factor in the determination of its final allocation factors. The AED-12CP is used by the Company for the sole purpose of allocating production plant assets.

Q. COULD YOU PLEASE PROVIDE AN ILLUSTRATIVE COMPARISON OF THE TRADITIONAL AED METHODOLOGY AND THE COMPANY'S METHODOLOGY?

A. As previously stated, where the Company's methodology appears to deviate from the traditional methodology is with the allocation of the excess demand and average demand components of allocation. Under the traditional methodology as described in the NARUC Cost Allocation Manual the average and excess components are determined using the following calculation methodology[1]:

$$A = \left(\frac{\text{Class Excess Demand}}{\text{Total System Excess Demand}}\right) * (1 - load\ factor)$$

$$B = \left(\frac{\text{Class Average Demand}}{\text{Total System Average Demand}}\right) * (load\ factor)$$

$$C = A + B$$

Where: A = The excess demand portion of the allocation ratio
B = The average demand portion of the allocation ratio
C = The total allocation ratio

Under the Company's methodology the average and excess components are determined using the following calculation method:

$$A = (\text{Total System Excess Demand}) * \left(\frac{Class\ NCP}{Total\ System\ NCP}\right)$$

$$B = (\text{Total System Average Demand}) * \left(\frac{Class\ Energy\ Usage}{Total\ System\ Energy\ Usage}\right)$$

$$C = \frac{A + B}{sum\ of\ all\ classes\ A + B}$$

Where: A = The excess demand portion of the allocation ratio
B = The average demand portion of the allocation ratio

[1] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, pp 49 and 82.

C = The total allocation ratio

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

A. Yes. The 12CP allocation relies on the theory that no single 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 12CP allocation factor is determined for each rate class 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 HOW THE COMPANY CLASSIFIES CUSTOMER AND DEMAND COMPONENTS ASSOCIATED WITH DISTRIBUTION PLANT.

A. As previously stated the second process in a CCOSS is to categorize or classify costs as those that are demand-related, energy-related, or customer-related. The Company utilizes a minimum-size system approach to classify distribution plant items in FERC accounts 365 – 368 as demand and customer related costs.

Q. PLEASE DESCRIBE THE MECHANICS OF A MINIMUM-SIZE SYSTEM STUDY ("MSS").

A. Many distribution system assets can be classified as having both a customer and an energy component. For instance, distribution substations are built to serve customers, but are often expanded to meet increases in customer loads. A MSS study attempts to separate the customer-related portion of total system costs from those associated with serving loads (or service volumes). A MSS study estimates the hypothetical minimum costs of developing a system to serve customers with no load. These calculations can include subjectivity through the use of accounting and engineering analyses to develop assumptions about the minimum sizes and costs associated with various distribution system components, while still satisfying system requirements such as pole height and efficient conductor and transformer sizes. The costs associated with these "minimum" components are then added together to derive the total minimum costs associated with the hypothetical system with no energy usage. This estimate is then divided by total actual system costs in order to approximate the customer-related share of overall distribution system costs.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S MSS STUDY.

A. The MSS study found that 64 percent of costs associated with Account 364 (Poles, Towers and Fixtures) at the primary-voltage level were customer-related as opposed to demand-related.[2] Similarly, the MSS study found that at the primary level, 31 percent of costs associated with Account 365 (Overhead Conductors and Devices), 100 percent of costs associated with Accounts 366 (Underground Conduit) and 34 percent of the costs associated with Account 367 (Underground Conductors and Devices) are customer-related.[3] At the secondary-voltage level, the MSS found that 100% percent of costs associated with Account 364 (Poles, Towers and Fixtures) and

[2] H. Edwin Overcast, Direct Testimony, 12:14-18.
[3] H. Edwin Overcast, Direct Testimony, 13:1-5 and 13:11-13.

Account 365 (Overhead Conductors and Devices) are customer-related.[4] Finally, with regard to Account 368 (Line Transformers), the MSS study showed that 60 percent of account costs are customer-related as opposed to demand-related.[5]

Q. PLEASE DESCRIBE THE COMPANY'S NCP-PRIMARY MEASURE OF DEMAND.

A. The Company uses the NCP-Primary allocation method to allocate the portions of the distribution system that have been functionalized and classified to the primary system and are demand-related. The NCP-Primary allocator is a traditional measure of non-coincident customer class peaks, or NCP, measured as the maximum hourly system demand attributable to each rate class for a given year, in this case, the 2013 calendar year. The NCP-Primary allocator utilized in the Company's CCOSS, is used to allocate the demand-related portion of the primary 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).[6]

B. ALTERNATIVE CCOSS

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

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[4] H. Edwin Overcast, Direct Testimony, 12:13-15 and 13:2-3.
[5] H. Edwin Overcast, Direct Testimony, 13:19-20.
[6] H. Edwin Overcast, Direct Testimony, Schedule HEO-4.

A. Yes. I disagree with three allocation factors used by the Company in its CCOSS including: (1) the use of a minimum-size system approach to allocate distribution plant accounts 364 through 368; (2) the calculation of the excess portion of the AED factor; (3) the allocation of line transformers on the basis of average number of customers; and (4) the allocation of Regulatory Expenses using a composite labor and plant allocator.

Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES THE COMPANY'S ALLOCATION FACTORS TO THE ONES YOU ARE RECOMMENDING?

A. Yes. Schedule DED-1 compares my proposed CCOSS allocation factors to the Company's. The first column in the schedule lists the account name, and the second, third and fourth columns compare the Company's proposed allocation method with my recommendations.

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

A. Consistent with cost causation principles, production plant costs should be allocated to customer classes consistent with the cost impact that the 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 peak method, and twelve-month coincident peak method. 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.[7]

Q. PLEASE EXPLAIN THE ALTERNATIVE CCOSS THAT YOU HAVE PREPARED IN THIS PROCEEDING.

A. I have prepared two Alternative CCOSS Models. The first CCOSS model shown on Schedule DED-2, utilizes the Company's AED12CP allocation method for production plant, correcting the calculation of the excess option of the factor as discussed above. The second Alternative CCOSS model, Schedule DED-3, allocates production plant using an Average and Peak ("A&12CP") methodology, using the 12 coincident peaks for the peak portion of the factor. The NARUC cost allocation manual recognizes both the Average and Excess and Average and Peak allocation methods as appropriate methods to allocate production plant.[8]

Q. PLEASE EXPLAIN WHY THE AVERAGE AND PEAK METHOD IS AN APPROPRIATE METHOD TO ALLOCATE PRODUCTION PLANT.

A. As previously stated, energy weighting methods recognize that energy loads are also a contributing factor of production plant costs. The NARUC cost allocation manual

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

recognizes the Average and Peak ("A&P") method, as one that may be utilized to allocate production plant.[9] The A&P 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. I have used 12CP as the demand proportion of the allocation factor in my Alternative CCOSS.

Q. WHY DO YOU BELIEVE THE MSS STUDY SHOULD NOT BE USED FOR CCOSS PURPOSES IN THIS PROCEEDING?

A. The results of the MSS study should not be used for ratemaking purposes in this proceeding because the MSS study is based upon a straw man of hypotheticals that hinge on a number of unverifiable assumptions. Data limitations are one of the main reasons for this methodological deficiency. Utilities typically do not retain the needed cost information with sufficient specificity to be able to calculate customer-related distribution costs with any degree of certainty.

Q. HAS THE ACADEMIC LITERATURE IN UTILITY REGULATION QUESTIONED THE USE OF MSS STUDIES?

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

A. Yes. Bonbright, et al., in his seminal work on public utility rates, raised a number of serious questions about using an MSS methodology to assign costs. Principal among Bonbright's concerns was the lack of empirical support in academic literature for a causal relationship between distribution system costs and the number of customers. The true driving factors, utility distribution system costs, are much more complicated, and depend on a host of other factors, such as the size of a service territory and the population density within.

> … the annual costs of this phantom, minimum-sized distribution system are related as customer costs and are deducted from the annual costs of the existing system, only the balance being included among those demand-related costs to be mentioned in the following section. Their [minimum system costs] inclusion among the customer costs is defended on that, since they vary directly with the area of the distribution system … they therefore vary directly with the number of customers.
>
> …
>
> What this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customer per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customer does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system.[10]

Q. PLEASE EXPLAIN YOUR PROPOSED METHOD OF ALLOCATING DISTRIBUTION PLANT ACCOUNTS 364 THROUGH 368.

[10] James C. Bonbright, et al. Principles of Public Utility Rates. 1988 Edition, p. 491.

A. As previously stated I do not believe a MSS method should be used in this proceeding to classify Distribution Plant accounts 364 through 368. The use of a minimum-size system approach causes a larger proportion of distribution costs to be classified as customer related, which ultimately reflects a higher amount of fixed costs that should be recovered through the customer charge. As previously discussed, certain items and accounts should be classified as customer related and recovered through the customer charge. Therefore, I have classified these accounts as 100 percent demand related and I have allocated these accounts using Class NCP.[11] The method of allocating Distribution Plant Accounts 364 through 368 on a 100 percent demand basis is a valid and widely accepted allocation method.

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF LINE TRANSFORMERS?

A. No. The Company classifies line transformers as 60 percent customer-related and 40 percent demand-related using the MSS methodology. As previously stated, typically demand-related items are allocated using an allocation factor derived from a measure of demand, either CP or NCP. However, the Company has allocated all of Account 368 (Line Transformers) on the basis of the average number of customers, despite the Company's own classification of 40 percent of line transformers as demand related. Aside from my previous concerns regarding the use of the MSS approach to allocate line transformers the Company has erroneously allocated this account on the

[11] The relevant expense and depreciation accounts associated with these distribution plant accounts, where appropriate, have been modified to follow the allocation of the distribution plant accounts.

basis of the number of customers.[12] In the instance that the Commission does not accept my alternative CCOSS recommendations, in which I have allocated Account 368 using a NCP-Secondary allocation, the Commission should question the Company's allocation approach which is allocated purely on a per-customer basis. It is my recommendation that at the very least the demand related portion of this account should be allocated using a factor developed from a measure of demand, preferably the NCP-Secondary allocator.

Q. DO YOU AGREE WITH THE COMPANY'S ALLOCATION OF REGULATORY EXPENSES?

A. No. The Company allocates Regulatory Commission Expense on the basis of a composite labor and plant allocator. The Commission assesses regulatory expenses to jurisdictional utilities pursuant to Section 386.370.1 of the Missouri Revised Statutes, which states that Commission regulatory assessments shall be calculated based on a ratio of gross operating revenues for all jurisdictional utilities for the preceding calendar year.[13] I recommend allocating these expenses based on gross Missouri retail sales revenue, to reflect more accurately the driving force behind these expenses.

C. CCOSS RECOMMENDATIONS

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

[12] The Company has indicated in response to OPC Data Response 5064, that the demand portion of line transformers was allocated on NCP, however, the CCOSS model provided by the Company reflects otherwise.
[13] Missouri Revised Statutes, § 386.370.1(2).

A. Yes, and those have been identified and compared to the Company's original CCOSS results in Schedule DED-4. I have also prepared two alternative CCOSS using these recommended allocation factors, which is shown in Schedule DED-2 and DED-3. For comparison purposes, results of the Company's CCOSS are additionally shown within Schedule DED-5.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I have prepared two recommended CCOSS Models which the Commission should consider. The first CCOSS model shown on Schedule DED-2, utilizes the Company's AED12CP allocation method for production plant, correcting the calculation of the excess option of the factor as discussed above. The second Alternative CCOSS model, Schedule DED-3, allocates production plant using an Average and Peak ("A&12CP") methodology, using the 12 coincident peaks for the peak portion of the factor.

In addition, I recommend that the Commission adopt the Company's proposed CCOSS modified so that instead of using a MSS approach for accounts 364 through 368, NCP allocation at the primary and secondary distribution levels presented on DED-1 is used. In addition, the allocation of line transformers should be allocated on the basis of a NCP-Secondary allocator rather than the number of customers. Finally, Regulatory Expenses should be allocated using gross retail sales revenue in place of the Company's current composite labor and plant allocator.

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.

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 class cost of service study ("CCOSS") as one of several important inputs in the development of rates. The Commission has clearly noted in prior decisions that it will not be bound to strict adherence to cost of service outcomes in setting rates.[14]

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 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.[15] 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.[16]

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

[14] 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.
[15] 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.
[16] 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.

A. The Company proposes to: (1) increase jurisdictional rates by approximately $23.7 million;[17] (2) significantly increase customer charges;[18] and (3) move rates as near to its proposed CCOSS as practical.[19]

B. REVENUE DISTRIBUTION

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

A. Yes. 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, in some instances, 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 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

[17] Excludes the energy efficiency revenue requirement of $577,722.
[18] Direct Testimony of W. Scott Keith, 14:4-7.
[19] Company's Response to OPC Data Request DR-5040.

closer to costs, but conditions those increases to minimize rate shock and ensure policy equity.f

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

A. Rates in the Company's last rate case were established through a Settlement Agreement between the parties to that proceeding.[20] The rate increase agreed to in the Settlement was based upon an equal percentage basis whereby each class received a uniform percent increase, as did each rate element within each class' rate design.[21] The residential class rate increase, however, was allocated exclusively to the (volumetric) energy charge[22] with no increase assigned to the (fixed) customer charge.[23] The Commission determined that the rates proposed in the Settlement were just and reasonable.[24]

Q. PLEASE DISCUSS THE COMPANY'S CURRENTLY PROPOSED REVENUE DISTRIBUTION.

A. The Company makes a number of revenue distribution proposals in this proceeding. All of which, as noted earlier, are designed to "condition" the strict results of the CCOSS. The Company's revenue distribution proposal includes:

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[20] Company's Response to OPC Data Request 5040.
[21] Company's Response to OPC Data Request 5040.
[22] Company's Response to OPC Data Request 5040.
[23] Company's Response to OPC Data Request 5040.
[24] In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company, Case No. ER-2011-004, Order Approving Global Agreement, June 1, 2006.

- An increase of no greater than 1.40 times the system average for rate classes estimated to be earning a return below the system average, excluding all lighting classes.
- Ensuring that no class receives a rate decrease.
- 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.
- Ensuring that the pre-Missouri Energy Efficiency Investment Act ("MEEIA") energy efficiency revenue requirement is recovered through a uniform volumetric charge.
- Ensuring that rate classes estimating to be generating a class return between the average proposed return and 125 percent of the average proposed return, receive an increase no greater than 50 percent of the average proposed increase; and
- The Special Contract and Large Power classes cost of service results be specifically adjusted to reflect changes related to the nature of the service provided and the addition of new customers which occurred after the test year.[25]

Q. PLEASE DESCRIBE THE COMPANY'S ADDITIONAL ADJUSTMENTS.

A. The Company makes two additional revenue distribution adjustments. The first revenue distribution adjustment includes an increase of about $370,221 to the Special Contract ("SC-P") class in order to adjust for the transfer of the Special Contract customer's credits to other rate classes, instead of being directly assigned to the Special Contract customer.[26] The Company also makes a similar offset of $5,823,200

[25] The Direct Testimony of W. Scott Keith 13:1-18.
[26] Company's Response to OPC Data Request 5070.

to the Large Power ("LP") class to smooth an alleged revenue deficiency associated with the impact of new large power customers not included in the 2013 test year.

Q. WHY DID THE COMPANY EXCLUDE THE LIGHTING CLASSES FROM RECEIVING A PORTION OF THE REVENUE INCREASE?

A. The Company indicated that it excluded lighting classes from any rate increase because (1) its cost of service results indicated these classes were earning reasonable returns (relative to costs)[27] and (2) represent less than two percent of the Company's overall jurisdictional revenues.[28]

Q. PLEASE DESCRIBE A RELATIVE RATE OF RETURN.

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.[29] 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 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

[27] The Company's Response to OPC Data Request 5080.
[28] The Company's Response to OPC Data Request 5080.
[29] The Company uses the terminology "Unitized Rate of Return" or "UROR" which is calculated in the same manner as a relative rate of return.

amount less than the Company's overall rate of return. Schedule DED-6 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. However, the Company did not file a CCOSS in its last rate proceeding and relied on the CCOSS that was filed in Case No. ER-2011-0004. Schedule DED-7 provides a comparison of the RRORs from the 2011 rate case and those filed in this proceeding. The residential class RRORs decrease from 0.75 (prior case) to 0.62 in the current rate case. However, the General Power ("GP"), Special Contract ("SC-P") and Total Electric Building ("TEB") classes all appear to be earning RRORs greater than the prior rate case.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend a two-step revenue distribution methodology. In the first step, each of the under-earning classes is assigned an increase that is 1.10 times the system average increase. In the second step, the residual revenue deficiency between the Company's requested return and the first step revenue increase is allocated to the remaining classes in relation to their current test year revenues. My recommended revenue distribution gradually moves each of the under-earning classes to a RROR of 1.0. Under my proposed approach, residential classes receive 50 percent of the Company's proposed total rate increase, an increase that is lower than the Company's proposal to allocate 64 percent of its requested increase to the residential classes. The primary difference in the two approaches is that my approach tempers the overall increase by assigning part of the proposed rate increase to over-earning classes. The results of my recommended revenue distribution using the Company's revenue requirement are shown on Schedule DED-8. I have also prepared a recommended revenue distribution with a revenue requirement at a level of 20 percent lower than the Company's requested revenue requirement, which is available as DED-9.

Q. WHY DID YOU INCLUDE THE LIGHTING CLASSES IN YOUR PROPOSED REVENUE DISTRIBUTION?

A. The results of the Company's CCOSS indicate that the only lighting class currently providing a return above the total system return is the Private Lighting class. The remaining three lighting classes, Miscellaneous Services ("MS"), Street Lights ("SPL"), and Special Lights ("LS"), are all estimated to be earning returns significantly below the total system return. This finding weakens the Company's original justification for excluding these classes from a proposed increase. Further, there is no reason to exclude these classes simply because they are a small share of overall revenues. Lastly, and as noted earlier, CCOSS results are merely a guide to help support the rate design process and do not need to be slavishly followed throughout the entire rate design process, particularly when such adherence could undermine other important ratemaking goals.

C. RATE DESIGN

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

A. The Company is proposing to change the rate structure of many of its classes from one that relies upon combinations of fixed and variable charges to one that increases the emphasis on fixed charges. The Company justifies this proposed change upon its belief that such a rate design modification is consistent with cost causation principles.[30] The Company states the current rate structure places too much emphasis on volumetric recovery of fixed costs which puts the Company at risk for not earning its allowed return.[31] The Company further asserts that its proposal to increase fixed charges will insulate it from external factors influencing sales, such as weather or greater energy efficiency.[32] Furthermore, the Company states that the proposed rate design is more economically efficient by sending the correct price signals to customers.[33] A summary of the Company's current and proposed customer charges has been provided in Schedule DED-10.

Q. PLEASE EXPLAIN THE COMPANY'S SCHEDULE RG PROPOSALS.

A. The Company proposes to apply an increase to both the customer and volumetric charges for the Residential ("RG") customer class.[34] The Company is proposing to move towards fixed cost recovery; for the Residential class the proposed customer charge is an increase of almost 50 percent more than the current rate of $12.52 to $18.75. The volumetric charge will also increase in order to collect the remaining class revenue requirement.

Q. PLEASE EXPLAIN THE COMPANY'S COMMERCIAL RATE DESIGN PROPOSALS (SCHEDULE CB).

[30] H. Edwin Overcast, Direct Testimony, 22:3-4.
[31] H. Edwin Overcast, Direct Testimony, 21:15, 22:1-3.
[32] H. Edwin Overcast, Direct Testimony, 22:1:3.
[33] H. Edwin Overcast, Direct Testimony, 26:13-17.
[34] H. Edwin Overcast, Direct Testimony, 29:1-5.

A. The rate schedule for the Small Commercial class consists of two components: a fixed customer charge and an energy charge. The Company's proposal increases the customer charge by just over 50 percent from $21.32 to $32.00. The remaining amount of revenue is apportioned to the energy charge.

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

A. Schedule DED-11 provides a survey of current residential and small commercial customer charges for major electric distribution companies operating in the Mid-west region.[35] The Company's proposed Residential customer charge of $18.75 per month is higher than the average residential system charge of $8.85 for the surveyed Mid-west region utilities. There are only two out of the 58 utilities surveyed, that have a residential customer charge greater than the Company's proposal. These two utilities' customer charges in the amount of $19.00 are only slightly higher than the Company's proposal.

Q. WHAT ABOUT THE SMALL COMMERCIAL CUSTOMER CHARGES?

A. The Company's proposed Small Commercial customer charge of $32.00 per month is higher than the average small commercial customer charge of $13.47 for other regional utilities. In fact, all 58 of the electric distribution companies in the survey referenced earlier have customer charges lower than the Company.

[35] The Mid-west region includes Missouri, Kansas, Iowa, Illinois, Indiana, Michigan, Minnesota, North Dakota, South Dakota, Ohio and Wisconsin.

Q. WHAT IS THE BASIS FOR THE COMPANY'S PROPOSED CUSTOMER CHARGE INCREASE?

A. The Company proposes to apply a 50 percent increase to the customer charge for the Residential rate class since it is difficult to apply fixed charges to these classes on a demand-charge type basis.[36] The Company argues that a 50 percent increase in the residential customer charge is necessary, in lieu of the creation of residential customer demand charges, in order to make residential rates more efficient.[37] The Company maintains that a customer charge that recovers the utility's fixed costs of providing service will alleviate intra-class cost subsidies for similarly situated customers.[38] The proposed 50 percent increase, however, is a somewhat arbitrary increase and simply based upon the Company's attempt to apply some form of rate gradualism to its proposed shift in the structure of its residential rates.[39]

Q. IS THE COMPANY'S PROPOSAL TO INCREASE THE ALLOCATION OF ITS COSTS INTO FIXED CHARGES UNUSUAL?

A. No, the proposal is not unusual, but is rarely adopted by state regulators, particularly for electric utilities. The Company's proposals are similar to a more generalized method of setting fixed charges known as a "straight fixed variable" ("SFV") rate design. A SFV rate design simply attempts to assume most all utility costs into fixed monthly charges. This form of rate design originated with the Federal Energy

[36] H. Edwin Overcast, Direct Testimony, 25:22-23.
[37] H. Edwin Overcast, Direct Testimony, 29:1-5.
[38] H. Edwin Overcast, Direct Testimony, 26:5-10.
[39] Company's Response to OPC Data Request 5075.

Regulatory Commission ("FERC") when it promulgated Order No. 636 restructuring the natural gas transmission system.[40] At the time, the purpose of adopting SFV for natural gas transmission was to promote the development of a competitive market for natural gas at the wellhead by eliminating transportation rate differentials.[41] Since that time many utilities have proposed, but very few have been granted, strict SFV rate designs. Other utilities over the past several years (natural gas and electric), however, have made less stringent SFV-type proposals whereby many, but not all of the costs considered "fixed" are included in a fixed monthly fee with some very small variable (volumetric) charge component. This form of rate design is often referred to as a "modified SFV" and like its strict SFV counterpart, is usually offered by utilities as a means of simply shifting revenue recovery risk away from itself and onto ratepayers.

Q. DO MANY STATES UTILIZE AN SFV FOR ELECTRIC UTILITIES?

A. No, according to a 2013 survey published by the Edison Electric Institute (the trade association for the electric utility industry), there are only three states with an approved SFV electric rate design including Connecticut (Connecticut Light & Power), Illinois (Commonwealth Edison), and Mississippi (Mississippi Power).[42]

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CLASS TOTAL REVENUE?

[40] FERC. Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Docket No. RM91-11-0000; Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Docket No. RM87-34-065; Final Rule Order No. 636, Issued April 8, 1992, p. 126.
[41] FERC. "Cost-of-Service Rates Manual." June 1999, p. 32.
[42] Newton, Mark N. et. al, (January 2013), "Alternative Regulation for Evolving Utility Challenges: An Updated Survey," Edison Electric Institute, p. 25.

A. The customer charge revenue associated with the Residential class has been provided, along with customer charge revenue recoveries for the other customer classes, in Schedule DED-12. As shown on this schedule, for all but the commercial class, each class's customer charge revenue is less than 10 percent of total revenue.

Q. IS THE COMPANY'S PROPOSED RATE DESIGN 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 an 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.[43]

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:

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from \$7.50 to \$8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[44]

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

[43] 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.
[44] 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. 9299. Order No. 85374, Issued February 22, 2013, p. 99.

as one of three major approaches to delink utility revenues from sales. One alternative listed was SFV rate design, which as stated earlier, is a variation of the Company's customer charge proposals. 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.[45]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

[45] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 5. Emphasis added.

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. <u>While SFV rates are being considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies</u>. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[46]

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.[47]

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 1,000 kWh per month. Customer 2 represents a smaller customer using an average of only 660 kWh per month, approximately a third less than the hypothetical system average. Customer 3 likewise represents a larger customer using an average of 1,330 kWh per month, approximately a third more than the hypothetical system average. The schedule

[46] "Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design" (September 2009), National Action Plan for Energy Efficiency, pp. 13-14.
[47] Company's Response to OPC Data Request 5056.

shows that customers using close to the system average will see an increase of 7.6 percent in the summer months and 8.2 percent during the winter months. Those customers using greater than average use will actually incur a slightly less increase of 6.6 percent and 7.2 percent during the summer and winter, respectively. Low-use residential customers will see their rates increase by as much as 9.8 percent during both the summer and winter rate structures.

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 rates, variable rates, block rates, 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 often 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.

D. CUSTOMER CHARGES

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

A. Yes, and that has been provided in Schedule DED-14. "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. However, the Company utilizes a minimum size system methodology to classify portions of the distribution plant, which results in a larger amount of costs being classified as customer related, thereby suggesting a larger customer charge.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. In most cases, the Company's current customer charges are under collecting for commonly-recognized customer costs. The Residential class customer-related costs are $38.41 compared to the current customer charge revenue per customer of $12.47. The Commercial class is estimated to have customer-related costs at $51.63 compared to its current system charge revenue per customer of $21.51.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. My specific customer charge recommendations are provided on Schedule DED-13. I recommend no increase in the customer charges in this proceeding. As revealed in my survey of current customer charges in the Mid-west provided in DED-11, it is apparent that Empire's current Residential customer charge is the fifth highest customer charge among the 58 utilities analyzed. Only five other utilities had a customer charge higher than the Company's current rate of $12.52, with customer charges ranging from $14.00 to $19.00. Additionally, my analysis provided in DED-14 shows that under the Company's proposed CCOSS the current customer charges collect 34 percent of the total customer related costs. I have also prepared Schedule DED-15, which provides the customer costs as a result of my alternative CCOSS. The alternative CCOSS shows a Residential customer cost of $17.24 per customer—indicating that the current customer charges collect 72 percent of the total customer related costs. Therefore, it is my opinion that an increase in customer charges is not necessary in this proceeding.

E. 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 adjusted to reflect the demand charge reflected in the CCOSS results. The remaining revenue requirement is recovered through the energy charge.

Q. WHAT ARE YOUR VOLUMETRIC RATE RECOMMENDATIONS?

A. My volumetric rate recommendations differ from those offered by the Company. These differences are a function of my alternative CCOSS, the resulting alternative revenue distribution, my recommended customer charges, and the treatment of demand charges. My recommended revenue distribution effectively allocates the revenue increase to the classes which are earning less than the overall system rate of return by distributing the revenue requirement among the classes in proportion to their test year revenues. As previously stated, my customer charge recommendation maintains the Company's current customer charges for each rate class. Costs not recovered through the customer charge are 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 alternative rates based upon my alternative CCOSS and recommended revenue distribution are provided in Schedules DED-8, DED- 9, and DED-17..

Q. HOW DO YOUR RECOMMENDATIONS IMPACT THE RESIDENTIAL AND SMALL COMMERCIAL CUSTOMER CLASSES?

A. I have presented my revenue distribution and rate design recommendations under both the Company's requested increase and assuming a rate increase that is 20 percent of what the Company requested. It is important to note that while I am using the Company's requested revenue requirement, this is for illustrative and comparative purposes only. Likewise, the 20 percent comparison is shown to illustrate the rate design under a lower revenue requirement than requested by the Company.

Under these two methods, Residential customers would see a volumetric rate increase of some 6.5 percent under the proposed increase and 1.3 percent under the lower 20 percent of the Company's requested increase. This compares to the Company's proposal of about 3 percent.

Similar to the Company's rate design proposal, I also propose to maintain the same relationship between the summer and winter rates. In the first volumetric rate block this will result in a summer energy rate of $0.12194/kWh and a winter energy rate of $0.12194/kWh and in the second volumetric rate block the energy rate is $0.12194/kWh and $0.10044/kWh for summer and winter, respectively. Under the lower revenue requirement, in the first volumetric rate block this will result in a summer energy rate of $0.11631/kWh and a winter energy rate of $0.11631/kWh. In the second volumetric rate block the energy rate is $0.11631/kWh and $0.09481/kWh for summer and winter, respectively.

The larger percentage increase in my volumetric rate recommendation versus the Company's volumetric rate proposal, under the Company's requested revenue increase, is the result of my recommendation for customer charges to remain unchanged. Although, my volumetric rate increase appears to be larger than the Company's proposal, Schedule DED-16 shows that the overall distribution bill impact for a Residential customer under my rate design recommendations is less than the Company's proposal. A comparison of my revenue distribution and rate design recommendations at both the Company's full rate increase request and at a lower increase of 20 percent of its request to Empire's current and proposed rates of the Company has been provided in Schedule DED-17.

F. 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 1.10 times 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 Company's proposed increase to the customer charges should be rejected since customers are unable to avoid these charges it may have an adverse

impact on customers with low usage. Additionally, by moving fixed costs from the volumetric charges to the customer charges, customers may lose the incentive to engage in energy efficiency and conservation measures an outcome inconsistent with the Commission's energy conservation goals.

V. SUMMARY OF RECOMMENDATIONS

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

I have prepared two recommended CCOSS Models which the Commission should consider. The first CCOSS model utilizes the Company's AED12CP allocation method for production plant, correcting the calculation of the excess option of the factor as discussed above. The second Alternative CCOSS model allocates production plant using an Average and Peak ("A&12CP") methodology, using the 12 coincident peaks for the peak portion of the factor.

I recommend that the Commission adopt the Company's proposed CCOSS modified so that instead of using a MSS approach for accounts 364 through 368, NCP allocation at the primary and secondary distribution levels is used. In addition, the allocation of line transformers should be on the basis of a NCP-Secondary allocator rather than the number of customers. Finally, Regulatory Expenses should be allocated using gross retail sales revenue in place of the Company's current composite labor and plant allocator.

Q. PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS.

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 1.10 times 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 Company's proposed increase to the customer charges should be rejected since customers are unable to avoid these charges. It may also have an adverse impact on customers with low usage. Additionally, by moving fixed costs from the volumetric charges to the customer charges, customers may lose the incentive to engage in energy efficiency and conservation measures which is an outcome inconsistent with the Commission's energy conservation goals.

Q. DOES THIS COMPLETE YOUR PREFILED TESTIMONY FILED ON FEBRUARY 11, 2015?

A. Yes, it does.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
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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.

<u>PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS</u>

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.

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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.

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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.

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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.

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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.

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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.

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

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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 24^{th} 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. 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.

2. 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.

3. 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.

4. 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.

5. 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.

6. 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.

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

12. 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.

13. 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.

14. 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.

15. 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

16. 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.

17. 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.

18. 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.

19. 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.

20. 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.

21. 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.

22. 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.

23. 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.

24. 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.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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.

36. 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)

37. 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.

38. 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.

39. 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.

40. 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.

41. 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.

42. 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.

43. 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.

44. 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.

45. 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.

46. 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.

47. 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.

48. 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.

49. 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.

50. 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.

51. 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.

52. 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.

53. 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.

54. 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.

55. 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.

56. 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.

57. 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.

58. 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.

59. 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.

60. 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)

61. 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)

62. 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.

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

64. 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.

65. 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).

66. 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.

67. 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.

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

69. 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.

70. 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.

71. 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.

72. 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)

73. 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.

74. 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.

75. 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.

76. 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).

77. 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.

78. 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.

79. Expert Affidavit Before the 19^{th} 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.

80. 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)

81. 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.

82. 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.

83. 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).

84. 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.

85. 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.

86. 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

87. 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.

88. 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.

89. 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.

90. 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.

91. 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.

92. 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.

93. 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)

94. 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.

95. 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.

96. 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.

97. 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.

98. 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.

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

100. 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.

101. 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).

102. 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.

103. 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.

104. 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.

105. 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.

106. 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.

107. 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.

108. 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.

109. 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.

110. 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.

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

112. 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.

113. 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.

114. 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

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Empire Factor Description
RATE BASE			
Intangible Plant			
301	Organization	Total Plant in Service	Total Plant in Service
Production Plant			
310, 330, 340	Land and Land Rights	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
311, 331, 341	Structures and Improvements	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
312, 342	Boiler Plant Equipment	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
343	Engines and Generators	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
314, 333, 344	Turbogenerator Units	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
315, 334, 345	Accessory Electric Equipment	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
316, 332, 335, 346	Misc. Power Plant Equipment	AED12CP(Alternative CCOSS 1)/A&12CP (Alternative CCOSS 2)	AED12CP
Transmission Plant			
350	Land and Land Rights	12CP - Transmission Lines	12CP - Transmission Lines
352	Structures and Improvements	12CP - Transmission Lines	12CP - Transmission Lines
353	Station Equipment	12CP - Transmission Lines	12CP - Transmission Lines
354	Towers and Fixtures	12CP - Transmission Lines	12CP - Transmission Lines
355	Poles and Fixtures	12CP - Transmission Lines	12CP - Transmission Lines
356	Overhead Conductors and Devices	12CP - Transmission Lines	12CP - Transmission Lines
Distribution Plant			
360	Land & Land Rights	NCP-Primary	NCP-Primary
361	Structures & Improvements	NCP-Primary	NCP-Primary
362	Station Equipment	NCP-Primary	NCP-Primary
364	Poles, Towers and Fixtures		
	Poles, Towers and Fixtures - Primary Voltage	NCP-Primary	NCP-Primary, Number of Customers
	Poles, Towers and Fixtures - Secondary Voltage	NCP-Secondary	Number of Customers
365	Overhead Conductors and Devices		
	Overhead Conductors and Devices - Primary Voltage	NCP-Primary	NCP-Primary, Number of Customers
	Overhead Conductors and Devices - Secondary Voltage	NCP-Secondary	Number of Customers
366	Underground Conduit		
	Underground Conduit - Primary Voltage	NCP-Primary	Number of Customers
367	Underground Conductors and Devices		
	Underground Conductors and Devices - Primary Voltage	NCP-Primary	NCP-Primary, Number of Customers
368	Lines Transformers	NCP-Secondary	Number of Customers
369	Services	Weighted Services Investment	Weighted Services Investment
370	Meters	Weighted Meter Investment	Weighted Meter Investment
371	Installations on Customer Premises PR-L	Weighted Services Investment	Weighted Services Investment
373	Street Lighting and Signal Systems	Street Lighting Direct Assignment	Street Lighting Direct Assignment

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Empire Factor Description
General Plant			
389	Land & Land Rights	Labor Allocator	Labor Allocator
390	Structures and Improvements	Labor Allocator	Labor Allocator
391	Office Furniture & Equipment	Labor Allocator	Labor Allocator
392	Transportation Equipment	Labor Allocator	Labor Allocator
393	Stores Equipment	Labor Allocator	Labor Allocator
394	Tools, Shop and Garage Equipment	Labor Allocator	Labor Allocator
395	Laboratory Equipment	Labor Allocator	Labor Allocator
396	Power Operated Equipment	Labor Allocator	Labor Allocator
397	Communication Equipment	Labor Allocator	Labor Allocator
398	Misc. Equipment	Labor Allocator	Labor Allocator
Depreciation Reserve			
	Intangible	Total Plant in Service	Total Plant in Service
	Transmission	12CP - Transmission Lines	12CP - Transmission Lines
	Procurement Supply	AED12CP	AED12CP
	StreetLighting	Street Light Direct Assignment	Street Light Direct Assignment
	Primary-Distribution	Total Primary Distributiion Plant	Total Primary Distribution Plant
	Overhead Lines	Account 365 Overhead Lines	Account 365 Overhead Lines
	Underground Lines	Account 367 Underground Lines	Account 367 Underground Lines
	Transformers	NCP - Secondary	Number of Customers
	Services	Account 369 Services	Account 369 Services
	Metering	Account 370 Meters	Account 370 Meters
	Other Property on Customers Premise	Account 371 Installations on Customer Premises	Account 371 Installations on Customer Premises
	General	Labor Allocator	Labor Allocator
Other Rate Base Items			
	Deferred Fuel Cost	Energy Sales adjusted for losses	Energy Sales adjusted for losses
	Prepayments	Total Plant in Service, Energy Sales adjusted for losses	Total Plant in Service, Energy Sales adjusted for losses
	Cash Working Capital-Fuel	Energy Sales adjusted for losses	Energy Sales adjusted for losses
	Cash Working Capital-Revenue	Total Plant in Service	Total Plant in Service
	Cash Working Capital-Labor	Labor Allocator	Labor Allocator
	Cash Working Capital-Plant	Total Plant in Service	Total Plant in Service
	Deferred ITC	Total Plant in Service	Total Plant in Service
	Customer Advances for Construction	Cash Deposits	Cash Desposits
	Materials and Supplies	Total Plant in Service	Total Plant in Service
	Regulatory Assets - Generation	AED12CP	AED12CP
	Regulatory Assets - Distribution	Total Distribution Plant	Total Distribution Plant
	Regulatory Assets - Pension and Labor	Labor Allocator	Labor Allocator
	Customer Deposits	Cash Deposits	Cash Desposits
	Deferred Pension Asset	Labor Allocator	Labor Allocator
	Deferred Income Tax	Total Plant in Service	Total Plant in Service
	Deffered State Tax	Total Plant in Service	Total Plant in Service

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Empire Factor Description
OPERATIONS AND MAINTENANCE EXPENSES			
Production Expense			
500, 535, 546	Supervision and Engineering	Labor Allocator	Labor Allocator
501, 547	Fuel	Energy Sales - adjusted for losses	Energy Sales - adjusted for losses
505, 507, 537, 538	Generation Expense	AED12CP	AED12CP
539, 549	Misc. Generation Expenses	AED12CP	AED12CP
555	Purchase Power Expenses	Energy Sales - adjusted for losses	Energy Sales - adjusted for losses
	Other Variable Expenses	Energy Sales - adjusted for losses	Energy Sales - adjusted for losses
556	Load Dispatch	Load Dispatch Expense	Load Dispatch Expense
557	Other Purchase Power	Energy Sales - adjusted for losses	Energy Sales - adjusted for losses
Transmission Expense			
560	Supervision and Engineering	Labor Allocator	Labor Allocator
561	Load Dispatching	12CP - Transmission Lines	12CP - Transmission Lines
562	Station Expenses	12CP - Transmission Lines	12CP - Transmission Lines
563	Overhead Line Expenses	12CP - Transmission Lines	12CP - Transmission Lines
565	Transmission by Others-Demand	12CP - Transmission Lines	12CP - Transmission Lines
565	Transmission by Others-Energy	12CP - Transmission Lines	12CP - Transmission Lines
566	Miscellaneous Expenses	12CP - Transmission Lines	12CP - Transmission Lines
567	Rents	12CP - Transmission Lines	12CP - Transmission Lines
Distribution Expense			
Operations Expenses			
580	Operation Supervision & Engineering	Labor Allocator	Labor Allocator
582	Station Expenses	NCP-Primary	NCP-Primary
583	Overhead Line Expenses	Account 365 Overhead Lines	Accounts 365 Overhead Lines
584	Underground Line Expenses	Account 367 Underground Lines	Accounts 367 Underground Lines
585	Street Light and Signal Systems	Account 373 Street Lighting and Signal Systems	Account 373 Street Lighting and Signal Systems
586	Meter Expenses	Account 370 Meters	Account 370 Meters
587	Customer Installation Expenses	Account 369 Services	Account 369 Services
588	Misc. Distribution Expenses	Total Distribution Plant	Total Distribution Plant
589	Rents	Total Distribution Plant	Total Distribution Plant
OPERATIONS AND MAINTENANCE EXPENSES			
Production Maintenance Expenses			
510, 541, 551	Supervision and Engineering	Labor Allocator	Labor Allocator
511, 552, 542, 543	Maintenance of Structures	AED12CP	AED12CP
512, 513, 544, 553	Maintenance of Generation Plant	AED12CP	AED12CP
506, 514, 545, 554	Maintenance of Misc. Plant	AED12CP	AED12CP
Transmission Maintenance Expense			
568	Supervision and Engineering	Labor Allocator	Labor Allocator
569	Maintenance of Structures	12CP - Transmission Lines	12CP - Transmission Lines
570	Maintenance of Station Equipment	12CP - Transmission Lines	12CP - Transmission Lines
571	Maintenance of Overhead Lines	12CP - Transmission Lines	12CP - Transmission Lines

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Empire Factor Description
Distribution Maintenance Expenses			
590	Maint. Supervision & Engineering	Labor Allocator	Labor Allocator
591	Maint. of Structures	Account 360 Land and Land Rights	Account 360 Land and Land Rights
592	Maint. of Station Equipment	Account 362 Station Equipment	Account 362 Station Equipment
593	Maintenance of Overhead Lines	Account 365 Overhead Lines	Accounts 365 Overhead Lines
594	Maintenance of Underground Lines	Account 367 Underground Lines	Accounts 367 Underground Lines
595	Maintenance of Line Transformers	Account 368 Line Transformers	Account 368 Line Transformers
596	Maintenance of Street Lights	Account 373 Street Lighting and Signal Systems	Account 373 Street Lighting and Signal Systems
597	Maintenance of Meters	Account 370 Meters	Account 370 Meters
598	Maintenance of Misc. Plant	Total Distribution Plant	Total Distribution Plant
Customer Account Expense			
901	Supervision	Account 903 Customer Records and Collection Expenses	Account 903 Customer Records and Collection Expenses
902	Meter Reading Expenses	Meter Reading Expenses	Meter Reading Expenses
903	Customer Records & Collection	Account 903 Customer Records and Collection Expenses Analysis	Account 903 Customer Records and Collection Expenses Analysis
904	Uncollectible Accounts	Account Write-Offs	Account Write-Offs
905	Misc. Customer Accounts	Account 903 Customer Reacords and Collection Expenses	Accont 903 Customer Records and Collection Expenses
Customer Service & Inform. Exp.			
907, 908	Customer Assistance Exp Electric	Account 908 Customer Service Expenses Analysis	Account 908 Customer Service Expenses Analysis
909	Supervision	Account 908 Customer Service Expenses Analysis	Account 908 Customer Service Expenses Analysis
910	Customer Assistance Expenses	Number of Customers	Number of Customers
911	Information, Instructional Advertising	Number of Customers	Number of Customers
912	Misc Customer Serv & Inform Expen	Account 912 Customer Service Expenses Analysis	Account 912 Customer Service Expenses Analysis
Sales Expenses			
916	Demonstrating & Selling Expenses	Account 908 Customer Service Expenses	Account 908 Customer Service Expenses
Administrative & General Expenses			
Operation Expenses			
920	A & G Salaries	Labor Allocator	Labor Allocator
921	Office Supplies & Expenses	Labor Allocator	Labor Allocator
922	Admin. Expenses Transferred-Credit	Labor Allocator	Labor Allocator
923	Outside Services Employed	Labor Allocator	Labor Allocator
924	Property Insurance	Total Plant in Service	Total Plant in Service
925	Injuries & Damages	Total Plant in Service	Total Plant in Service
926	Employee Pensions & Benefits	Labor Allocator	Labor Allocator
928	Regulatory Commission Expense	Sales Revenue	Labor Allocator and Total Plant in Service
929	Duplicate Charges - Credit	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
930.1	General Administrative Expenses	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
931	Rents	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
Maintenance Expenses			
935	Maintenance of General Plant	Total Plant in Service	Total Plant in Service

Comparison of CCOSS Allocation Factors

FERC Account	Description	Recommended Factor	Empire Factor Description
OTHER COST OF SERVICE COMPONENTS			
Depreciation Expense			
	Intangible	Total Plant in Service	Total Plant in Service
	Transmission	12CP - Transmission Lines	12CP - Transmission Lines
	Procurement Supply	AED12CP	AED12CP
	StreetLighting	Account 373 Street Lights	Account 373 Street Lights
	Primary-Distribution	Account 362 Station Equipment (NCP-Primary)	Account 362 Station Equipment (NCP-Primary)
	Overhead Lines	Account 365 Overhead Lines	Account 365 Overhead Lines
	Underground Lines	Account 366 Underground Lines	Account 366 Underground Lines
	Transformers	Account 368 Line Transformers	Account 368 Line Transformers
	Services	Account 369 Services	Account 369 Services
	Metering	Account 370 Meters	Account 370 Meters
	Other Property on Customers Premise	Account 369 Services	Account 369 Services
	General	Labor Allocator (General Plant)	Labor Allocator (General Plant)
General Taxes			
	Payroll Taxes	LaborAllocator	Labor Allocator
	Payroll Taxes - Generation	LaborAllocator	Labor Allocator
	Unemployment Tax	LaborAllocator	Labor Allocator
	Real Estate Taxes	Total Plant in Service	Total Plant in Service
Franchise and Revenue Taxes			
	Franchise	Sales Revenue	Sales Revenue
Federal Income Taxes			
	Federal Income Taxes - Current	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
	State Income Taxes - Current	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
	Provision for Deferred FIT	Labor Allocator and Total Plant in Service	Labor Allocator and Total Plant in Service
Other Operating Revenues			
	Revenues	Sales Revenue	Sales Revenue
	Forfeited Discounts - Mo	Written-off Revenue	Written-off Revenue
	Reconnect Charges-Missouri	Collection Expenses	Collection Expenses
	Ot Elec Rev-Off-Sys	Energy Sales - adjusted for losses	Energy Sales - adjusted for losses
	Rent From Elec Property-Mo	Account 364 Poles, Towers, and Fixtures	Account 364 Poles, Towers, and Fixtures
	Other Electric Revenues	12CP - Transmission Lines	12CP - Transmission Lines
	Other Electric Revenues - Direct Assign	Residential Direct Assignment	Residential Direct Assignment
	Other Electric - Transmission	12CP - Transmission Lines	12CP - Transmission Lines
	Gains/Losses from Disp. of Utility Plant	Total Plant in Service	Total Plant in Service
	Interest on Customer Deposits	Account 369 Services	Account 369 Services

Source: Direct Testimony of H. Edwin Overcast; Schedule HEO-5.

Alternative CCOSS 1: Average and Excess 12CP Under Recommended Cost Allocation Factors

Account Description	Total Missouri	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
OPERATING REVENUES													
Utility Sales Revenues	$ 448,805,193	$ 208,264,926	$ 42,245,689	$ 10,278,959	$ 85,561,340	$ 3,528,082	$ 37,556,352	$ 78,524	$ 54,383,299	$ 14,189	$ 2,321,702	$ 4,452,932	$ 119,198
Total Operating Revenues	$ 455,183,283	$ 211,531,924	$ 42,727,979	$ 10,411,575	$ 86,595,795	$ 3,584,232	$ 38,109,778	$ 79,252	$ 55,234,597	$ 14,320	$ 2,321,702	$ 4,452,932	$ 119,198
OPERATING EXPENSES													
Production	$ 171,551,969	$ 73,747,518	$ 13,183,981	$ 3,756,928	$ 34,657,610	$ 2,270,130	$ 15,574,032	$ 18,523	$ 27,036,632	$ 5,319	$ 727,735	$ 548,294	$ 25,266
Transmission	$ 14,494,784	$ 7,107,447	$ 1,145,205	$ 314,898	$ 2,456,329	$ 133,328	$ 1,314,119	$ 1,728	$ 2,021,419	$ 311	$ -	$ -	$ -
Distribution	$ 24,059,213	$ 12,408,328	$ 2,641,202	$ 635,968	$ 3,591,540	$ 4,708	$ 1,852,460	$ 6,420	$ 2,343,727	$ 376	$ 242,725	$ 281,649	$ 50,110
Customer Acctg & Service	$ 11,038,436	$ 8,745,561	$ 1,235,696	$ 208,794	$ 300,338	$ 8,616	$ 136,553	$ 1,292	$ 301,741	$ 4,298	$ 26,756	$ 60,157	$ 8,635
Admin & General	$ 37,863,085	$ 20,746,418	$ 3,713,715	$ 878,616	$ 5,139,813	$ 201,017	$ 2,702,928	$ 6,266	$ 3,991,081	$ 4,214	$ 217,115	$ 233,339	$ 28,562
Total Operating Expenses	$ 259,007,487	$ 122,755,271	$ 21,919,798	$ 5,795,204	$ 46,145,630	$ 2,617,798	$ 21,580,093	$ 34,231	$ 35,694,601	$ 14,519	$ 1,214,332	$ 1,123,438	$ 112,573
EXPENSES	$ 62,274,122	$ 32,463,254	$ 5,621,199	$ 1,438,819	$ 9,395,117	$ 295,879	$ 5,074,130	$ 11,099	$ 7,008,326	$ 1,333	$ 427,412	$ 481,332	$ 56,220
TAXES OTHER THAN INCOME TAX	$ 21,833,107	$ 11,325,864	$ 1,964,323	$ 501,805	$ 3,311,965	$ 115,639	$ 1,783,988	$ 3,766	$ 2,506,834	$ 799	$ 141,721	$ 159,104	$ 17,299
INCOME BEFORE INCOME TAXES	$ 112,068,567	$ 44,987,534	$ 13,222,659	$ 2,675,748	$ 27,743,083	$ 554,916	$ 9,671,568	$ 30,156	$ 10,024,836	$ (2,331)	$ 538,236	$ 2,689,058	$ (66,894)
INCOME TAXES													
Income Taxes - Current	$ 21,008,801	$ 10,788,912	$ 1,854,805	$ 481,917	$ 3,244,512	$ 110,630	$ 1,759,557	$ 3,652	$ 2,450,422	$ 456	$ 139,866	$ 157,139	$ 16,933
Provision for Deferred FIT	$ 10,448,853	$ 5,365,930	$ 922,498	$ 239,684	$ 1,613,678	$ 55,023	$ 875,126	$ 1,816	$ 1,218,732	$ 227	$ 69,563	$ 78,154	$ 8,422
ITC Adjustment - Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Federal Income Taxes	$ 31,457,654	$ 16,154,842	$ 2,777,304	$ 721,602	$ 4,858,190	$ 165,653	$ 2,634,683	$ 5,469	$ 3,669,154	$ 683	$ 209,429	$ 235,293	$ 25,355
OPERATING INCOME	$ 80,610,913	$ 28,832,693	$ 10,445,355	$ 1,954,146	$ 22,884,893	$ 389,263	$ 7,036,885	$ 24,688	$ 6,355,682	$ (3,014)	$ 328,808	$ 2,453,765	$ (92,249)
Gains/Losses	$ (3,645,260)	$ (1,787,780)	$ (309,976)	$ (81,862)	$ (611,993)	$ (29,957)	$ (304,449)	$ (548)	$ (473,892)	$ (166)	$ (21,101)	$ (21,439)	$ (2,096)
Interest on Customer Deposits	$ (407,085)	$ (323,917)	$ (58,492)	$ (10,171)	$ (9,956)	$ -	$ (4,074)	$ (24)	$ -	$ -	$ -	$ -	$ (451)
NET INCOME	$ 76,558,568	$ 26,720,996	$ 10,076,887	$ 1,862,113	$ 22,262,943	$ 359,306	$ 6,728,362	$ 24,116	$ 5,881,790	$ (3,180)	$ 307,706	$ 2,432,326	$ (94,796)
RATE BASE	$ 1,142,391,460	$ 577,470,283	$ 97,015,648	$ 25,416,780	$ 180,554,388	$ 6,816,080	$ 97,115,035	$193,108	$ 139,906,370	$ 26,477	$ 8,041,761	$ 9,024,558	$ 810,972
RETURN ON RATE BASE	6.70%	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.69	1.55	1.09	1.84	0.79	1.03	1.86	0.63	-1.79	0.57	4.02	-1.74

Alternative CCOSS 2: Average 12CP Under Recommended Cost Allocation Factors

Account Description	Total Missouri	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
OPERATING REVENUES													
Utility Sales Revenues	$ 448,805,193	$ 208,264,926	$ 42,245,689	$ 10,278,959	$ 85,561,340	$ 3,528,082	$ 37,556,352	$ 78,524	$ 54,383,299	$ 14,189	$ 2,321,702	$ 4,452,932	$ 119,198
Total Operating Revenues	$ 455,183,283	$ 211,531,924	$ 42,727,979	$ 10,411,575	$ 86,595,795	$ 3,584,232	$ 38,109,778	$ 79,252	$ 55,234,597	$ 14,320	$ 2,321,702	$ 4,452,932	$ 119,198
OPERATING EXPENSES													
Production	$ 171,551,969	$ 72,532,385	$ 13,149,379	$ 3,763,730	$ 35,373,415	$ 2,356,915	$ 15,589,509	$ 18,301	$ 27,401,216	$ 65,823	$ 727,735	$ 548,294	$ 25,266
Transmission	$ 14,494,784	$ 7,107,447	$ 1,145,205	$ 314,898	$ 2,456,329	$ 133,328	$ 1,314,119	$ 1,728	$ 2,021,419	$ 311	$ -	$ -	$ -
Distribution	$ 24,059,213	$ 12,408,328	$ 2,641,202	$ 635,968	$ 3,591,540	$ 4,708	$ 1,852,460	$ 6,420	$ 2,343,727	$ 376	$ 242,725	$ 281,649	$ 50,110
Customer Acctg & Service	$ 11,038,436	$ 8,745,561	$ 1,235,696	$ 208,794	$ 300,338	$ 8,616	$ 136,553	$ 1,292	$ 301,741	$ 4,298	$ 26,756	$ 60,157	$ 8,635
Admin & General	$ 37,863,085	$ 19,976,614	$ 3,691,794	$ 882,926	$ 5,593,285	$ 255,997	$ 2,712,733	$ 6,125	$ 4,222,050	$ 42,544	$ 217,115	$ 233,339	$ 28,562
Total Operating Expenses	$ 259,007,487	$ 120,770,334	$ 21,863,276	$ 5,806,316	$ 47,314,907	$ 2,759,564	$ 21,605,374	$ 33,867	$ 36,290,153	$ 113,353	$ 1,214,332	$ 1,123,438	$ 112,573
EXPENSES	$ 62,274,122	$ 30,934,994	$ 5,577,681	$ 1,447,375	$ 10,295,378	$ 405,029	$ 5,093,595	$ 10,819	$ 7,466,859	$ 77,428	$ 427,412	$ 481,332	$ 56,220
TAXES OTHER THAN INCOME TAX	$ 21,833,107	$ 10,779,645	$ 1,948,769	$ 504,863	$ 3,633,729	$ 154,650	$ 1,790,945	$ 3,666	$ 2,670,719	$ 27,997	$ 141,721	$ 159,104	$ 17,299
INCOME BEFORE INCOME TAXES	$ 112,068,567	$ 49,046,950	$ 13,338,252	$ 2,653,022	$ 25,351,781	$ 264,989	$ 9,619,865	$ 30,899	$ 8,806,866	$ (204,457)	$ 538,236	$ 2,689,058	$ (66,894)
INCOME TAXES													
Income Taxes - Current	$ 21,008,801	$ 10,237,537	$ 1,839,105	$ 485,004	$ 3,569,314	$ 150,010	$ 1,766,579	$ 3,551	$ 2,615,854	$ 27,910	$ 139,866	$ 157,139	$ 16,933
Provision for Deferred FIT	$ 10,448,853	$ 5,091,700	$ 914,690	$ 241,220	$ 1,775,220	$ 74,608	$ 878,619	$ 1,766	$ 1,301,011	$ 13,881	$ 69,563	$ 78,154	$ 8,422
ITC Adjustment - Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Federal Income Taxes	$ 31,457,654	$ 15,329,237	$ 2,753,794	$ 726,224	$ 5,344,533	$ 224,618	$ 2,645,198	$ 5,318	$ 3,916,865	$ 41,791	$ 209,429	$ 235,293	$ 25,355
OPERATING INCOME	$ 80,610,913	$ 33,717,714	$ 10,584,458	$ 1,926,798	$ 20,007,248	$ 40,371	$ 6,974,667	$ 25,581	$ 4,890,002	$ (246,249)	$ 328,808	$ 2,453,765	$ (92,249)
Gains/Losses	$ (3,645,260)	$ (1,727,480)	$ (308,259)	$ (82,199)	$ (647,515)	$ (34,264)	$ (305,217)	$ (537)	$ (491,985)	$ (3,169)	$ (21,101)	$ (21,439)	$ (2,096)
Interest on Customer Deposits	$ (407,085)	$ (323,917)	$ (58,492)	$ (10,171)	$ (9,956)	$ -	$ (4,074)	$ (24)	$ -	$ -	$ -	$ -	$ (451)
NET INCOME	$ 76,558,568	$ 31,666,317	$ 10,217,706	$ 1,834,428	$ 19,349,777	$ 6,108	$ 6,665,376	$ 25,021	$ 4,398,017	$ (249,417)	$ 307,706	$ 2,432,326	$ (94,796)
RATE BASE	$ 1,142,391,460	$ 544,681,681	$ 96,081,981	$ 25,600,339	$ 199,869,342	$ 9,157,865	$ 97,532,645	$ 187,110	$ 149,744,121	$ 1,659,084	$ 8,041,761	$ 9,024,558	$ 810,972
RETURN ON RATE BASE	6.70%	5.81%	10.63%	7.17%	9.68%	0.07%	6.83%	13.37%	2.94%	-15.03%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.87	1.59	1.07	1.44	0.01	1.02	2.00	0.44	-2.24	0.57	4.02	-1.74

Comparison of Class Rates of Return Under Company's and Recommended Cost Allocation Factors

	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)
Company Proposed						
Return	4.18%	7.30%	6.39%	13.70%	4.13%	11.36%
Relative ROR	0.62	1.09	0.95	2.04	0.62	1.70
Alternative CCOSS 1 (AED12CP)						
Return	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%
Relative ROR	0.69	1.55	1.09	1.84	0.79	1.03
Alternative CCOSS 2 (A&P12CP)						
Return	5.81%	10.63%	7.17%	9.68%	0.07%	6.83%
Relative ROR	0.87	1.59	1.07	1.44	0.01	1.02

	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Company Proposed						
Return	13.77%	4.76%	-12.69%	3.04%	24.44%	-12.53%
Relative ROR	2.05	0.71	-1.89	0.45	3.65	-1.87
Alternative CCOSS 1 (AED12CP)						
Return	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative ROR	1.86	0.63	-1.79	0.57	4.02	-1.74
Alternative CCOSS 2 (A&P12CP)						
Return	13.37%	2.94%	-15.03%	3.83%	26.95%	-11.69%
Relative ROR	2.00	0.44	-2.24	0.57	4.02	-1.74

Source: Direct Testimony of H. Edwin Overcast, Schedule HEO-1; Company workpaper, Rate Design ER-2014-0351; Schedule DED-3; Schedule DED-4.

Results of the Company’s CCOSS

Witness: Dismukes
ER-2014-0351
Schedule DED-5

Account Description	Total Missouri	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Service (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
OPERATING													
Utility Sales Revenues	$ 448,805,193	$ 208,426,401	$ 42,254,146	$ 10,275,695	$ 85,481,002	$ 3,528,082	$ 37,512,710	$ 78,385	$ 54,346,223	$ 14,182	$ 2,318,718	$ 4,451,184	$ 118,466
Total Operating Revenues	$ 455,183,283	$ 211,693,398	$ 42,736,436	$ 10,408,311	$ 86,515,457	$ 3,584,232	$ 38,066,136	$ 79,113	$ 55,197,520	$ 14,313	$ 2,318,718	$ 4,451,184	$ 118,466
OPERATING													
Production	$ 171,551,969	$ 72,453,264	$ 13,266,897	$ 3,787,947	$ 35,359,229	$ 2,285,731	$ 15,517,975	$ 19,869	$ 27,435,763	$ 5,497	$ 779,079	$ 595,871	$ 44,848
Transmission	$ 14,494,784	$ 7,107,447	$ 1,145,205	$ 314,898	$ 2,456,329	$ 133,328	$ 1,314,119	$ 1,728	$ 2,021,419	$ 311	$ -	$ -	$ -
Distribution	$ 24,059,213	$ 14,756,264	$ 2,862,499	$ 606,471	$ 2,421,603	$ 4,716	$ 1,231,308	$ 4,457	$ 1,675,443	$ 279	$ 199,868	$ 255,941	$ 40,365
Customer Acctg & Service	$ 11,038,436	$ 8,745,561	$ 1,235,696	$ 208,794	$ 300,338	$ 8,616	$ 136,553	$ 1,292	$ 301,741	$ 4,298	$ 26,756	$ 60,157	$ 8,635
Admin & General	$ 37,863,085	$ 20,846,689	$ 3,921,262	$ 898,373	$ 5,066,604	$ 207,542	$ 2,405,690	$ 6,388	$ 3,984,674	$ 4,415	$ 234,928	$ 247,644	$ 38,875
Total Operating Expenses	$ 259,007,487	$ 123,909,224	$ 22,431,558	$ 5,816,483	$ 45,604,103	$ 2,639,933	$ 20,605,644	$ 33,735	$ 35,419,041	$ 14,801	$ 1,240,631	$ 1,159,612	$ 132,723
DEPRECIATION EXPENSES	$ 62,274,122	$ 33,120,111	$ 6,358,704	$ 1,502,792	$ 8,881,515	$ 315,546	$ 4,245,060	$ 10,478	$ 6,824,665	$ 1,420	$ 438,211	$ 504,233	$ 71,384
TAXES OTHER THAN INCOME TAX	$ 21,833,107	$ 11,512,654	$ 2,216,689	$ 524,902	$ 3,161,847	$ 122,667	$ 1,507,404	$ 3,606	$ 2,444,305	$ 834	$ 146,961	$ 168,238	$ 23,001
INCOME BEFORE INCOME TAXES	$ 112,068,567	$ 43,151,409	$ 11,729,485	$ 2,564,135	$ 28,867,991	$ 506,086	$ 11,708,028	$ 31,294	$ 10,509,509	$ (2,742)	$ 492,914	$ 2,619,100	$ (108,642)
INCOME TAXES													
Income Taxes - Current	$ 21,008,801	$ 11,010,123	$ 2,127,444	$ 506,771	$ 3,068,092	$ 117,726	$ 1,466,696	$ 3,450	$ 2,375,689	$ 488	$ 144,160	$ 165,601	$ 22,561
Provision for Deferred FIT	$ 10,448,853	$ 5,475,950	$ 1,058,097	$ 252,046	$ 1,525,934	$ 58,552	$ 729,470	$ 1,716	$ 1,181,563	$ 243	$ 71,699	$ 82,363	$ 11,221
ITC Adjustment - Net	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Federal Income Taxes	$ 31,457,654	$ 16,486,074	$ 3,185,540	$ 758,817	$ 4,594,025	$ 176,278	$ 2,196,166	$ 5,166	$ 3,557,252	$ 731	$ 215,859	$ 247,964	$ 33,782
OPERATING INCOME	$ 80,610,913	$ 26,665,335	$ 8,543,945	$ 1,805,318	$ 24,273,966	$ 329,808	$ 9,511,862	$ 26,128	$ 6,952,258	$ (3,473)	$ 277,055	$ 2,371,136	$ (142,424)
Gains/Losses	$ (3,645,260)	$ (1,805,341)	$ (336,169)	$ (84,324)	$ (598,449)	$ (30,730)	$ (275,668)	$ (536)	$ (467,829)	$ (170)	$ (21,356)	$ (21,942)	$ (2,747)
Interest on Customer Deposits	$ (407,085)	$ (323,917)	$ (58,492)	$ (10,171)	$ (9,956)	$ -	$ (4,074)	$ (24)	$ -	$ -	$ -	$ -	$ (451)
NET INCOME	$ 76,558,568	$ 24,536,078	$ 8,149,284	$ 1,710,823	$ 23,665,561	$ 299,077	$ 9,232,120	$ 25,569	$ 6,484,429	$ (3,644)	$ 255,700	$ 2,349,194	$ (145,621)
RATE BASE	$ 1,142,391,460	$ 587,187,119	$ 111,585,627	$ 26,784,980	$ 172,770,248	$ 7,237,933	$ 81,248,355	$ 185,727	$ 136,180,971	$ 28,703	$ 8,408,369	$ 9,610,797	$ 1,162,631
RETURN ON RATE	6.70%	4.18%	7.30%	6.39%	13.70%	4.13%	11.36%	13.77%	4.76%	-12.69%	3.04%	24.44%	-12.53%
Relative Rate of Return	1.00	0.62	1.09	0.95	2.04	0.62	1.70	2.05	0.71	(1.89)	0.45	3.65	(1.87)

Source: Direct Testimony of H. Edwin Overcast, Schedule HEO-1 and Schedule HEO-5.

Comparison of Company's Current and Proposed Class Rate of Returns

	Residential (RG)	Commercial (CB)	Small Heating (SH)	General Power (GP)	Transmission Praxair (SC-P)	Total Electric Building (TEB)
Current						
Return	4.18%	7.30%	6.39%	13.70%	4.13%	11.36%
Relative ROR	0.62	1.09	0.95	2.04	0.62	1.70
Proposed						
Return	5.78%	8.88%	8.00%	14.10%	4.52%	11.74%
Relative ROR	0.72	1.11	1.00	1.77	0.57	1.47

	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Current						
Return	13.77%	4.76%	-12.69%	3.04%	24.44%	-12.53%
Relative ROR	2.05	0.71	-1.89	0.45	3.65	-1.87
Proposed						
Return	14.14%	6.23%	-12.69%	3.04%	24.44%	-12.53%
Relative ROR	1.77	0.78	-1.59	0.38	3.06	-1.57

Source: Direct Testimony of H. Edwin Overcast, Schedule HEO-1; Company workpaper, Rate Design ER-2014-0351.

Comparison of Past and Present Class Rate of Returns

	Residential (RG)	Commercial (CB)	Commercial Small (SH)	General Power (GP)	Special Transmission (SC-P)	Total Electric Building (TEB)
Case No. ER-2011-0004						
Return	5.05%	7.94%	7.75%	10.04%	3.27%	9.22%
Relative ROR	0.75	1.18	1.15	1.50	0.49	1.37
Case No. ER-2014-0351						
Return	4.18%	7.30%	6.39%	13.70%	4.13%	11.36%
Relative ROR	0.62	1.09	0.95	2.04	0.62	1.70

	Feed Mill (PFM)	Large Power (LP)	Miscellanous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Case No. ER-2011-0004						
Return	20.94%	5.61%	11.08%	13.05%	25.05%	-0.57%
Relative ROR	3.12	0.84	1.65	1.94	3.73	-0.08
Case No. ER-2014-0351						
Return	13.77%	4.76%	-12.69%	3.04%	24.44%	-12.53%
Relative ROR	2.05	0.71	-1.89	0.45	3.65	-1.87

Source: Direct Testimony of H. Edwin Overcast, Schedule HEO-1; ER-2011-0004, June 2010 Electric Cost of Service Study.

Recommended Revenue Distribution at Company's Proposed Revenue Requirement

	Total	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Contract Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Cost of Service Results													
Operating Income	$ 76,558,568	$ 26,720,996	$ 10,076,887	$ 1,862,113	$ 22,262,943	$ 359,306	$ 6,728,362	$ 24,116	$ 5,881,790	$ (3,180)	$ 307,706	$ 2,432,326	$ (94,796)
Rate Base	$ 1,142,391,460	$ 577,470,283	$ 97,015,648	$ 25,416,780	$ 180,554,388	$ 6,816,080	$ 97,115,035	$ 193,108	$ 139,906,370	$ 26,477	$ 8,041,761	$ 9,024,558	$ 810,972
ROR	6.70%	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.69	1.55	1.09	1.84	0.79	1.03	1.86	0.63	-1.79	0.57	4.02	-1.74
Revenue Requirement Results													
Operating Income	$ 76,558,568	$ 26,720,996	$ 10,076,887	$ 1,862,113	$ 22,262,943	$ 359,306	$ 6,728,362	$ 24,116	$ 5,881,790	$ (3,180)	$ 307,706	$ 2,432,326	$ (94,796)
Rate Base	$ 1,142,391,460	$ 577,470,283	$ 97,015,648	$ 25,416,780	$ 180,554,388	$ 6,816,080	$ 97,115,035	$ 193,108	$ 139,906,370	$ 26,477	$ 8,041,761	$ 9,024,558	$ 810,972
ROR	6.70%	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.69	1.55	1.09	1.84	0.79	1.03	1.86	0.63	-1.79	0.57	4.02	-1.74
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 23,741,631												
Operating Income Deficiency	$ 14,627,545												
ROR Schedule	6.70%												
Step One Increase													
System ROR	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Incremental Income	$ 14,627,545	$ 11,978,784	$ (3,575,281)	$ (158,781)	$ (10,162,900)	$ 97,481	$ (220,095)	$ (11,175)	$ 3,494,183	$ 4,954	$ 231,221	$ (1,827,536)	$ 149,144
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	$ 23,741,631	$ 19,442,488	$ (5,802,955)	$ (257,713)	$ (16,495,169)	$ 158,219	$ (357,232)	$ (18,137)	$ 5,671,328	$ 8,042	$ 375,289	$ (2,966,231)	$ 242,073
Percent Increase @ System ROR	5.45%	9.73%	-14.02%	-2.56%	-19.91%	4.77%	-0.99%	-21.94%	10.24%	58.43%	16.57%	-68.26%	201.60%
Maximum Increase @ 1.10 Times System Average Increase	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%	5.99%
Required Percentage Increase with Limitation	5.99%	5.99%	0.00%	0.00%	0.00%	4.77%	0.00%	0.00%	5.99%	5.99%	5.99%	0.00%	5.99%
Initial Increase	$ 16,237,632	$ 11,973,616		$ 602,195		$ 198,863			$ 3,319,290	$ 824	$ 135,650		$ 7,193
Shortfall in Required Increase	$ 7,503,999												
Step Two Increase													
Increase	$ 164,895,988	$ -	$ 41,395,126	$ -	$ 82,846,435	$ -	$ 36,226,524	$ 82,683	$ -	$ -	$ -	$ 4,345,220	$ -
Allocation of Shortfall to Remaining Customer Classes	$ 7,503,999	$ -	$ 1,883,788	$ -	$ 3,770,132	$ -	$ 1,648,578	$ 3,763	$ -	$ -	$ -	$ 197,740	$ -
Total Required Increase	$ 23,741,631	$ 11,973,616	$ 1,883,788	$ 602,195	$ 3,770,132	$ 198,863	$ 1,648,578	$ 3,763	$ 3,319,290	$ 824	$ 135,650	$ 197,740	$ 7,193
Proposed Revenue Allocation													
ROR	7.98%	5.90%	11.58%	8.79%	13.62%	7.07%	7.97%	13.69%	5.67%	-10.09%	4.87%	28.30%	-11.14%
Incremental Income	$ 14,627,545	$ 7,377,109	$ 1,160,627	$ 371,020	$ 2,322,830	$ 122,522	$ 1,015,711	$ 2,318	$ 2,045,060	$ 508	$ 83,576	$ 121,830	$ 4,432
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	$ 23,741,631	$ 11,973,616	$ 1,883,788	$ 602,195	$ 3,770,132	$ 198,863	$ 1,648,578	$ 3,763	$ 3,319,290	$ 824	$ 135,650	$ 197,740	$ 7,193
Final Relative Rate of Return	1.00	0.74	1.45	1.10	1.71	0.89	1.00	1.71	0.71	-1.26	0.61	3.55	-1.40

Recommended Revenue Distribution at 20% of Company's Proposed Revenue Requirement

		Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Contract Praxair (SC-P)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Cost of Service Results													
Operating Income	$ 76,558,568	$ 26,720,996	$ 10,076,887	$ 1,862,113	$ 22,262,943	$ 359,306	$ 6,728,362	$ 24,116	$ 5,881,790	$ (3,180)	$ 307,706	$ 2,432,326	$ (94,796)
Rate Base	$ 1,142,391,460	$ 577,470,283	$ 97,015,648	$ 25,416,780	$ 180,554,388	$ 6,816,080	$ 97,115,035	$ 193,108	$ 139,906,370	$ 26,477	$ 8,041,761	$ 9,024,558	$ 810,972
ROR	6.70%	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.69	1.55	1.09	1.84	0.79	1.03	1.86	0.63	-1.79	0.57	4.02	-1.74
Revenue Requirement Results													
Operating Income	$ 76,558,568	$ 26,720,996	$ 10,076,887	$ 1,862,113	$ 22,262,943	$ 359,306	$ 6,728,362	$ 24,116	$ 5,881,790	$ (3,180)	$ 307,706	$ 2,432,326	$ (94,796)
Rate Base	$ 1,142,391,460	$ 577,470,283	$ 97,015,648	$ 25,416,780	$ 180,554,388	$ 6,816,080	$ 97,115,035	$ 193,108	$ 139,906,370	$ 26,477	$ 8,041,761	$ 9,024,558	$ 810,972
ROR	6.70%	4.63%	10.39%	7.33%	12.33%	5.27%	6.93%	12.49%	4.20%	-12.01%	3.83%	26.95%	-11.69%
Relative Rate of Return	1.00	0.69	1.55	1.09	1.84	0.79	1.03	1.86	0.63	-1.79	0.57	4.02	-1.74
Rate Schedule Specific Revenue Increase Allocation													
Revenue Requirement	$ 4,748,326												
Operating Income Deficiency	$ 2,925,509												
ROR Schedule	6.70%												
Step One Increase													
System ROR	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Incremental Income	$ 2,925,509	$ 11,978,784	$ (3,575,281)	$ (158,781)	$ (10,162,900)	$ 97,481	$ (220,095)	$ (11,175)	$ 3,494,183	$ 4,954	$ 231,221	$ (1,827,536)	$ 149,144
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	$ 4,748,326	$ 19,442,488	$ (5,802,955)	$ (257,713)	$ (16,495,169)	$ 158,219	$ (357,232)	$ (18,137)	$ 5,671,328	$ 8,042	$ 375,289	$ (2,966,231)	$ 242,073
Percent Increase @ System ROR	1.09%	9.73%	-14.02%	-2.56%	-19.91%	4.77%	-0.99%	-21.94%	10.24%	58.43%	16.57%	-68.26%	201.60%
Maximum Increase @ 1.10 Times System Average Increase	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%	1.20%
Required Percentage Increase with Limitation	1.20%	1.20%	0.00%	0.00%	0.00%	1.20%	0.00%	0.00%	1.20%	1.20%	1.20%	0.00%	1.20%
Initial Increase	$ 3,247,526	$ 2,394,723		$ 120,439		$ 39,773			$ 663,858	$ 165	$ 27,130		$ 1,439
Shortfall in Required Increase	$ 1,500,800												
Step Two Increase													
Increase	$ 164,895,988	$ -	$ 41,395,126	$ -	$ 82,846,435	$ -	$ 36,226,524	$ 82,683	$ -	$ -	$ -	$ 4,345,220	$ -
Allocation of Shortfall to Remaining Customer Classes	$ 1,500,800	$ -	$ 376,757.50	$ -	$ 754,026.35	$ -	$ 329,716	$ 753	$ -	$ -	$ -	$ 39,548	$ -
Total Required Increase	$ 4,748,326	$ 2,394,723	$ 376,758	$ 120,439	$ 754,026	$ 39,773	$ 329,716	$ 753	$ 663,858	$ 165	$ 27,130	$ 39,548	$ 1,439
Proposed Revenue Allocation													
ROR	6.96%	4.88%	10.63%	7.62%	12.59%	5.63%	7.14%	12.73%	4.50%	-11.63%	4.03%	27.22%	-11.58%
Incremental Income	$ 2,925,509	$ 1,475,422	$ 232,125	$ 74,204	$ 464,566	$ 24,504	$ 203,142	$ 464	$ 409,012	$ 102	$ 16,715	$ 24,366	$ 886
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	$ 4,748,326	$ 2,394,723	$ 376,758	$ 120,439	$ 754,026	$ 39,773	$ 329,716	$ 753	$ 663,858	$ 165	$ 27,130	$ 39,548	$ 1,439
Final Relative Rate of Return	1.00	0.70	1.53	1.09	1.81	0.81	1.03	1.83	0.65	-1.67	0.58	3.91	-1.66

Company's Current and Proposed Customer Charges

	Residential (RG)	Commercial (CB)	Commercial Small (SH)	General Power (GP)	Special Transmission (SC-P)	Total Electric Building (TEB)
Current Charge	$ 12.52	$ 21.32	$ 21.32	$ 67.00	$ 246.47	$ 66.99
Proposed Charges	$ 18.75	$ 32.00	$ 32.00	$ 76.00	$ 2,450.00	$ 62.00
Percentage Difference	50%	50%	50%	13%	894%	-7%

	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Current Charge	$ 27.65	$ 247.73	$ 19.51	$ -	$ -	$ -
Proposed Charges	$ 76.40	$ 3,790.00	$ 29.25	$ -	$ -	$ -
Percentage Difference	176%	1430%	50%	0%	0%	0%

Source: Company's workpaper, Rate Design ER-2014-0351.

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	$ 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
MI	Upper Peninsula Power Co	$ 12.00	$ 16.00
MI	Wisconsin Electric Power Co	$ 9.61	$ 15.00
MI	Wisconsin Public Service Corp[2]	$ 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[3]	$ 8.00	$ 10.00
MN	Northwestern Wisconsin Electric Co[4]	$ 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[5]	$ 10.43	$ 17.19

[1] Amana Society Service Co is not regulated by the Iowa Utilities Board.

[2] 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.

[3] Northern States Power Co - 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.

[4] 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.

[5] KCP&L Greater Missouri Operations Co. Provides 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
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
OH	The Toledo Edison Co	$ 4.00	$ 7.00
SD	Black Hills Power Inc	$ 10.00	$ 12.50
SD	MidAmerican Energy Co	$ 7.00	$ 10.00
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[6]	$ 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

[6] Northern States Power Co - 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 (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Transmission Praxair (SP-T)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)
Customer Charge Revenue	$ 18,874,564	$ 4,510,438	$ 786,815	$ 1,332,228	$ 2,958	$ 742,584	$ 2,544	$ 112,965	$ 273
Total Revenue	$ 199,875,347	$ 41,395,126	$ 10,052,427	$ 82,846,435	$ 3,319,615	$ 36,226,524	$ 82,683	$ 55,408,850	$ 13,762
Customer Charge as Percent of Cost of Service	9.4%	10.9%	7.8%	1.6%	0.1%	2.0%	3.1%	0.2%	2.0%

Source: Company workpaper, Rate Design ER-2014-0351.

Total Distribution Bill Changes 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	
Average Usage per Month (kWh)	1000		660		1330	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Service Charge	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52
Existing Volumetric Rate 1st Block	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490
Existing Volumetric Rate 2nd Block	$ 0.11490	$ 0.09340	$ 0.11490	$ 0.09340	$ 0.11490	$ 0.09340
Average Monthly Utility Bill Under Existing Rates	$ 127.42	$ 118.82	$ 88.35	$ 87.06	$ 165.34	$ 149.64
Proposed Rate Customer Charge	$ 18.75	$ 18.75	$ 18.75	$ 18.75	$ 18.75	$ 18.75
Proposed Volumetric Rate 1st Block	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840
Proposed Volumetric Rate 2nd Block	$ 0.11834	$ 0.09684	$ 0.11834	$ 0.09684	$ 0.11834	$ 0.09684
Average Monthly Utility Bill Under Proposed Rates	$ 137.13	$ 128.53	$ 96.89	$ 95.60	$ 176.18	$ 160.48
Percent Increase from Existing Rates to Proposed Rates	7.6%	8.2%	9.7%	9.8%	6.6%	7.2%

Source: Company workpaper, Rate Design ER-2014-0351.

Comparison of Customer related Costs to Customer Charges

	Total MO	Residential (RG)	Commercial (CB)	Commercial Small Heating (SH)	General Power (GP)	Special Contract Praxair (SP-T)	Total Electric Building (TEB)	Feed Mill (PFM)	Large Power (LP)	Miscellaneous Services (MS)	Street Lights (SPL)	Private Lights (PL)	Special Lights (LS)
Customer Related Costs per Company's CCOSS													
Distribution Primary	$ 24,914,416	$ 20,955,874	$ 2,900,736	$ 504,213	$ 304,645	$ 150	$ 162,895	$ 1,187	$ 8,127	$ 166	$ 1,093	$ 53,027	$ 22,304
Distribution Secondary	$ 34,680,144	$ 23,805,166	$ 5,929,561	$ 999,399	$ 871,634	$ 13,554	$ 394,696	$ 2,483	$ 148,946	$ 58	$ 1,041,524	$ 1,425,813	$ 47,308
Customer	$ 16,862,134	$ 13,384,909	$ 1,997,617	$ 347,673	$ 299,726	$ 15,612	$ 152,454	$ 2,901	$ 540,637	$ 9,510	$ 59,075	$ 36,985	$ 15,035
Total Customer-Related	$ 76,456,694	$ 58,145,948	$ 10,827,914	$ 1,851,284	$ 1,476,005	$ 29,316	$ 710,045	$ 6,572	$ 697,710	$ 9,734	$ 1,101,692	$ 1,515,825	$ 84,647
Average No. Customers	149,883	126,140	17,478	3,039	1,774	1	957	7	38	1	6	307	135
Monthly Customer-Related Costs/Customer	$ 42.51	$ 38.41	$ 51.63	$ 50.76	$ 69.34	$ 2,443.03	$ 61.82	$ 76.41	$ 1,530.06	$ 811.21	$ 15,301.28	$ 411.91	$ 52.38
Customer Charge Revenue	$ 26,365,368	$ 18,874,564	$ 4,510,438	$ 786,815	$ 1,332,228	$ 2,958	$ 742,584	$ 2,544	$ 112,965	$ 273			
Monthly Customer Charge Revenue/Customer	$ 14.66	$ 12.47	$ 21.51	$ 21.57	$ 62.58	$ 246.47	$ 64.66	$ 29.58	$ 247.73	$ 22.76	$ -	$ -	$ -
Relationship of Customer Charge Revenues to	34%	32%	42%	43%	90%	10%	105%	39%	16%	3%	0%	0%	0%

Source: Company Response to OPC DR 5001.

Comparison of Customer related Costs to Customer Charges Under Alternative CCOSS

	Total MO	Residential (RG)	Commercial (CB)	Commercial Space Heat (SH)	General Power (GP)	Praxair (SP-T)
Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Secondary	$ 19,829,963.20	$ 12,790,909.74	$ 3,049,772.48	$ 499,624.70	$ 606,353.10	$ 14,231.65
Customer	$ 16,862,133.70	$ 13,303,595.61	$ 1,992,318.69	$ 348,316.73	$ 341,676.39	$ 17,280.75
Total Customer-Related Costs	$ 36,692,096.90	$ 26,094,505.35	$ 5,042,091.17	$ 847,941.43	$ 948,029.49	$ 31,512.40
Average No. Customers	149,883	126,140	17,478	3,039	1,774	1
Monthly Customer-Related Costs/Customer	$ 20.40	$ 17.24	$ 24.04	$ 23.25	$ 44.53	$ 2,626.03
Customer Charge Revenue	$ 26,365,368	$ 18,874,564	$ 4,510,438	$ 786,815	$ 1,332,228	$ 2,958
Monthly Customer Charge Revenue/Customer	$ 14.66	$ 12.47	$ 21.51	$ 21.57	$ 62.58	$ 246.47
Relationship of Customer Charge Revenues to Customer-Related Costs	72%	72%	89%	93%	141%	9%

	Total Elec. Bldg (TEB)	Feed Mill (PFM)	Large Power (LP)	Misc. Lts (MS)	Street Lts. (SPL)	Private Lts. (PL)	Spec. Lts.
Distribution Primary	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Secondary	$ 242,994.49	$ 1,322.47	$ 157,599.06	$ 6.04	$1,038,258.57	$1,403,806.33	$ 25,084.56
Customer	$ 170,565.77	$ 2,897.07	$ 562,901.25	$ 9,366.22	$ 59,397.16	$ 38,931.47	$ 14,886.61
Total Customer-Related Costs	$ 413,560.27	$ 4,219.53	$ 720,500.31	$ 9,372.26	$1,097,655.73	$1,442,737.80	$ 39,971.16
Average No. Customers	957	7	38	1	6	307	135
Monthly Customer-Related Costs/Customer	$ 36.01	$ 49.06	$ 1,580.04	$ 781.02	$ 15,245.22	$ 392.05	$ 24.73
Customer Charge Revenue	$ 742,584	$ 2,544	$ 112,965	$ 273			
Monthly Customer Charge Revenue/Customer	$ 64.66	$ 29.58	$ 247.73	$ 22.76	$ -	$ -	$ -
Relationship of Customer Charge Revenues to Customer-Related Costs	180%	60%	16%	3%	0%	0%	0%

Note: Although there are two different Alternative CCOSS, the customer-related cost allocations were the same under CCOSS. The customer charges are calculated using the Company's average customer count. Customer charges were not individually calculated at each level of service.
Source: Schedule DED-2; Schedule DED-3.

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	
Average Usage per Month (kWh)	1000		660		1330	
	Summer	Winter	Summer	Winter	Summer	Winter
Existing Service Charge	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52
Existing Volumetric Rate 1st Block	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490	$ 0.11490
Existing Volumetric Rate 2nd Block	$ 0.11490	$ 0.09340	$ 0.11490	$ 0.09340	$ 0.11490	$ 0.09340
Average Monthly Utility Bill Under Existing Rates	$ 127.42	$ 118.82	$ 88.35	$ 87.06	$ 165.34	$ 149.64
Company's Proposed Rates						
Proposed Rate Customer Charge	$ 18.75	$ 18.75	$ 18.75	$ 18.75	$ 18.75	$ 18.75
Proposed Volumetric Rate 1st Block	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840	$ 0.11840
Proposed Volumetric Rate 2nd Block	$ 0.11834	$ 0.09684	$ 0.11834	$ 0.09684	$ 0.11834	$ 0.09684
Average Monthly Utility Bill Under Proposed Rates	$ 137.13	$ 128.53	$ 96.89	$ 95.60	$ 176.18	$ 160.48
Percent Increase from Existing Rates to Proposed Rates	7.6%	8.2%	9.7%	9.8%	6.6%	7.2%
Recommended Rates						
Proposed Rate Customer Charge	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52	$ 12.52
Proposed Volumetric Rate 1st Block	$ 0.12194	$ 0.12194	$ 0.12194	$ 0.12194	$ 0.12194	$ 0.12194
Proposed Volumetric Rate 2nd Block	$ 0.12194	$ 0.10044	$ 0.12194	$ 0.10044	$ 0.12194	$ 0.10044
Average Monthly Utility Bill Under Proposed Rates	$ 134.46	$ 125.86	$ 93.00	$ 91.71	$ 174.70	$ 159.01
Percent Increase from Existing Rates to Proposed Rates	5.5%	5.9%	5.3%	5.3%	5.7%	6.3%

Source: Company workpaper, Rate Design ER-2014-0351; Schedule DED-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 20% Company Revenue Requirement		Increase %
Residential Service (RG)													
Customer Charge	$	12.52	$	18.75	$	6.23	49.8%	$	12.52	0.0%	$	12.52	0.0%
Distribution													
Summer Energy Rate 1st Block	$	0.11490	$	0.11840	$	0.00	3.0%	$	0.12194	6.1%	$	0.11631	1.2%
Summer Energy Rate 2nd Block	$	0.11490	$	0.11834	$	0.00	3.0%	$	0.12194	6.1%	$	0.11631	1.2%
Winter Energy Rate 1st Block	$	0.11490	$	0.11840	$	0.00	3.0%	$	0.12194	6.1%	$	0.11631	1.2%
Winter Energy Rate 2nd Block	$	0.09340	$	0.09684	$	0.00	3.7%	$	0.10044	7.5%	$	0.09481	1.5%
Commercial (CB)													
Customer Charge	$	21.32	$	32.00	$	10.68	50.1%	$	21.32	0.0%	$	21.32	0.0%
Distribution													
Summer Energy Rate 1st Block	$	0.12370	$	0.12567	$	0.00	1.6%	$	0.12990	5.0%	$	0.12497	1.0%
Summer Energy Rate 2nd Block	$	0.12370	$	0.12561	$	0.00	1.5%	$	0.12984	5.0%	$	0.12491	1.0%
Winter Energy Rate 1st Block	$	0.12370	$	0.12567	$	0.00	1.6%	$	0.12990	5.0%	$	0.12497	1.0%
Winter Energy Rate 2nd Block	$	0.11120	$	0.11311	$	0.00	1.7%	$	0.11734	0.6%	$	0.11241	1.1%
Commercial Small Heating (SH)													
Customer Charge	$	21.32	$	32.00	$	10.68	50.1%	$	21.32	0.0%	$	21.32	0.0%
Distribution													
Summer Energy Rate 1st Block	$	0.11940	$	0.12408	$	0.00	3.9%	$	0.12584	5.4%	$	0.12201	2.2%
Summer Energy Rate 2nd Block	$	0.11940	$	0.12281	$	0.00	2.9%	$	0.12457	4.3%	$	0.12074	1.1%
Winter Energy Rate 1st Block	$	0.11940	$	0.12408	$	0.00	3.9%	$	0.12584	5.4%	$	0.12201	2.2%
Winter Energy Rate 2nd Block	$	0.08920	$	0.09261	$	0.00	3.8%	$	0.09437	5.8%	$	0.09054	1.5%

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 20% Company Revenue Requirement	Increase %
General Power (GP)								
Customer Charge	$ 67.00	$ 76.00	$ 9.00	13.4%	$ 67.00	0.0%	$ 67.00	0.0%
Distribution								
Summer Energy Rate 1st Block	$ 0.08700	$ 0.07871	$ (0.01)	-9.5%	$ 0.09034	3.8%	$ 0.08766	0.8%
Summer Energy Rate 2nd Block	$ 0.06830	$ 0.05997	$ (0.01)	-12.2%	$ 0.07164	4.9%	$ 0.06896	1.0%
Summer Energy Rate 3rd Block	$ 0.06170	$ 0.05337	$ (0.01)	-13.5%	$ 0.06504	5.4%	$ 0.06236	1.1%
Winter Energy Rate 1st Block	$ 0.07520	$ 0.06691	$ (0.01)	-11.0%	$ 0.07854	4.4%	$ 0.07586	0.9%
Winter Energy Rate 2nd Block	$ 0.06190	$ 0.05357	$ (0.01)	-13.5%	$ 0.06524	5.4%	$ 0.06256	1.1%
Winter Energy Rate 3rd Block	$ 0.06140	$ 0.05307	$ (0.01)	-13.6%	$ 0.06474	5.4%	$ 0.06206	1.1%
Distribution Demand								
Demand (Summer)	$ 7.07	$ 7.07000	$ -	0.0%	$ 7.40	4.6%	$ 7.13	0.8%
Demand (Winter)	$ 5.51	$ 5.51000	$ -	0.0%	$ 5.77	4.7%	$ 5.56	0.9%
Demand Facilities	$ 1.99800	$ 4.53300	$ 2.54	126.9%	$ 2.091	4.7%	$ 2.016	0.9%
Special Transmission-Praxair (SC-P)								
Customer Charge	$ 246.47	$ 2,450.00	$ 2,203.53	894.0%	$ 246.47	0.0%	$ 246.47	0.0%
Distribution								
Summer On-Peak kWh	$ 0.05150	$ 0.04528	$ (0.01)	-12.1%	$ 0.05342	3.7%	$ 0.05151	0.02%
Summer Shoulder kWh	$ 0.04160	$ 0.03538	$ (0.01)	-14.9%	$ 0.04352	4.6%	$ 0.04161	0.03%
Summer Off-Peak kWh	$ 0.03210	$ 0.02588	$ (0.01)	-19.4%	$ 0.03402	6.0%	$ 0.03211	0.03%
Winter On-Peak kWh	$ 0.03650	$ 0.03028	$ (0.01)	-17.0%	$ 0.03842	5.3%	$ 0.03651	0.03%
Winter Shoulder kWh	$ -	$ -	$ -	0.0%	$ -	0.0%	$ -	
Winter Off-Peak kWh	$ 0.03030	$ 0.02408	$ (0.01)	-20.5%	$ 0.03222	6.3%	$ 0.03031	0.04%
Distribution Demand								
Demand (Summer)	$ 23.95	$ 23.95	$ -	0.0%	$ 25.38	6.0%	$ 24.24	1.2%
Demand (Winter)	$ 16.27	$ 16.27	$ -	0.0%	$ 17.24	6.0%	$ 16.46	1.2%
Substation Facilities Demand	$ 0.481	$ 4.50	$ 4.02	835.6%	$ 0.51	6.0%	$ 0.49	1.9%
Interruptible Credit	$ (4.01)	$ (4.01)	$ -	0.0%	$ (4.01)	0.0%	$ (4.01)	0.0%

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 20% Company Revenue Requirement		Increase %
Total Electric Building (TEB)													
Customer Charge	$	66.99	$	62.00	$	(4.99)	-7.4%	$	66.99	0.0%	$	66.99	0.0%
Distribution Energy													
Summer Energy Rate 1st Block	$	0.10160	$	0.09278	$	(0.01)	-8.7%	$	0.10464	3.0%	$	0.10171	0.1%
Summer Energy Rate 2nd Block	$	0.07960	$	0.06615	$	(0.01)	-16.9%	$	0.08324	4.6%	$	0.08031	0.9%
Summer Energy Rate 3rd Block	$	0.07210	$	0.05865	$	(0.01)	-18.7%	$	0.07574	5.0%	$	0.07281	1.0%
Witner Energy Rate 1st Block	$	0.07770	$	0.06888	$	(0.01)	-11.4%	$	0.08074	3.9%	$	0.07781	0.1%
Winter Energy Rate 2nd Block	$	0.06300	$	0.04955	$	(0.01)	-21.3%	$	0.06664	5.8%	$	0.06371	1.1%
Winter Energy Rate 3rd Block	$	0.06190	$	0.04845	$	(0.01)	-21.7%	$	0.06554	5.9%	$	0.06261	1.1%
Distribution Demand													
Demand (Summer)	$	3.30	$	3.30	$	-	0.0%	$	3.45	4.5%	$	3.33	0.9%
Demand (Winter)	$	2.71	$	2.71	$	-	0.0%	$	2.84	4.8%	$	2.73	0.7%
Substation Facilities Demand	$	1.997	$	4.60	$	2.60	130.3%	$	2.09	4.7%	$	2.02	1.2%
Feed Mill (PFM)													
Customer Charge	$	27.65	$	76.40	$	48.75	176.3%	$	27.65	0.0%	$	27.65	0.0%
Distribution Energy													
Summer Energy Rate 1st Block	$	0.18020	$	0.17291	$	(0.01)	-4.0%	$	0.18849	4.6%	$	0.18183	0.9%
Summer Energy Rate 2nd Block	$	0.18020	$	0.17291	$	(0.01)	-4.0%	$	0.18849	4.6%	$	0.18183	0.9%
Winter Energy Rate 1st Block	$	0.18020	$	0.17291	$	(0.01)	-4.0%	$	0.18849	4.6%	$	0.18183	0.9%
Winter Energy Rate 2nd Block	$	0.16370	$	0.15641	$	(0.01)	-4.5%	$	0.17199	5.1%	$	0.16533	1.0%

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 20% Company Revenue Requirement	Increase %
Large Power (LP)								
Customer Charge	$ 247.73	$ 3,790.00	$ 3,542.27	1429.9%	$ 247.73	0.0%	$ 247.73	0.0%
Distribution								
Summer Energy Rate 1st Block	$ 0.06710	$ 0.06262	$ (0.004)	-6.7%	$ 0.06986	4.1%	$ 0.06725	0.2%
Summer Energy Rate 2nd Block	$ 0.03630	$ 0.03232	$ (0.004)	-11.0%	$ 0.03956	9.0%	$ 0.03695	1.8%
Winter Energy Rate 1st Block	$ 0.0596	$ 0.05512	$ (0.004)	-7.5%	$ 0.06236	4.6%	$ 0.05975	0.3%
Winter Energy Rate 2nd Block	$ 0.0350	$ 0.03102	$ (0.004)	-11.4%	$ 0.03826	9.3%	$ 0.03565	1.9%
Distribution Demand								
Demand (Summer)	$ 13.70	$ 13.70	$ -	0.0%	$ 14.52	5.6%	$ 13.86	1.2%
Demand (Winter)	$ 7.57	$ 7.57	$ -	0.0%	$ 8.02	5.9%	$ 7.66	1.2%
Demand Facilities	$ 1.6490	$ 4.50	$ 2.85	172.9%	$ 1.75	6.1%	$ 1.67	1.3%
Miscellaneous Services (MS)								
Customer Charge	$ 19.51	$ 29.25	$ 9.74	49.9%	$ 19.51	0.0%	$ 19.51	0.0%
Distribution Energy								
Summer Energy Rate	$ 0.10170	$ 0.10070	$ (0.00)	-1.0%	$ 0.10790	6.1%	$ 0.10290	1.2%
Winter Energy Rate	$ 0.10170	$ 0.10070	$ (0.00)	-1.0%	$ 0.10790	6.1%	$ 0.10290	1.2%
Municipal Street Lights - SPL								
Distribution								
4,000 Lumen Incandescent	$ 65.55	$ 65.55	$ -	0.0%	$ 69.48	6.0%	$ 66.34	1.2%
7,000 Lumen Mercury	$ 89.02	$ 89.02	$ -	0.0%	$ 94.35	6.0%	$ 90.09	1.2%
11,000 Lumen Mercury	$ 106.85	$ 106.85	$ -	0.0%	$ 113.25	6.0%	$ 108.13	1.2%
20,000 Lumen Mercury	$ 152.97	$ 152.97	$ -	0.0%	$ 162.14	6.0%	$ 154.80	1.2%
53,000 Lumen Mercury	$ 258.08	$ 258.08	$ -	0.0%	$ 273.54	6.0%	$ 261.17	1.2%
6,000 Lumen HP Sodium	$ 83.42	$ 83.42	$ -	0.0%	$ 88.42	6.0%	$ 84.42	1.2%
16,000 Lumen HP Sodium	$ 104.43	$ 104.43	$ -	0.0%	$ 110.69	6.0%	$ 105.68	1.2%
27,500 Lumen HP Sodium	$ 135.91	$ 135.91	$ -	0.0%	$ 144.05	6.0%	$ 137.54	1.2%
50,000 Lumen HP Sodium	$ 193.68	$ 193.68	$ -	0.0%	$ 205.30	6.0%	$ 196.00	1.2%
130,000 Lumen HP Sodium	$ 312.56	$ 312.56	$ -	0.0%	$ 331.29	6.0%	$ 316.31	1.2%
12,000 Lumen MH	$ 130.55	$ 130.55	$ -	0.0%	$ 138.37	6.0%	$ 132.11	1.2%
20,500 Lumen MH	$ 159.99	$ 159.99	$ -	0.0%	$ 169.57	6.0%	$ 161.91	1.2%
36,000 Lumen MH	$ 214.03	$ 214.03	$ -	0.0%	$ 226.90	6.0%	$ 216.60	1.2%
110,000 Lumen MH	$ 472.96	$ 472.96	$ -	0.0%	$ 472.96	0.0%	$ 472.96	0.0%

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 20% Company Revenue Requirement	Increase %
Private Lighting Service - PL								
Distribution								
6,800 Lumen Std Mercury	$ 15.79	$ 15.79	$ -	0.0%	$ 16.51	4.6%	$ 15.93	0.9%
20,000 Lumen Std Mercury	$ 26.28	$ 26.28	$ -	0.0%	$ 27.48	4.6%	$ 26.52	0.9%
54,000 Lumen Std Mercury	$ 50.37	$ 50.37	$ -	0.0%	$ 52.66	4.6%	$ 50.83	0.9%
6,000 Lumen Std Sodium	$ 14.58	$ 14.58	$ -	0.0%	$ 15.24	4.6%	$ 14.71	0.9%
16,000 Lumen Std Sodium	$ 21.22	$ 21.22	$ -	0.0%	$ 22.19	4.6%	$ 21.41	0.9%
27,500 Lumen Std Sodium	$ 30.67	$ 30.67	$ -	0.0%	$ 32.07	4.6%	$ 30.95	0.9%
50,000 Lumen Std Sodium	$ 35.57	$ 35.57	$ -	0.0%	$ 37.19	4.6%	$ 35.89	0.9%
12,000 Lumen MH	$ 24.60	$ 24.60	$ -	0.0%	$ 25.72	4.6%	$ 24.82	0.9%
20,500 Lumen MH	$ 32.83	$ 32.83	$ -	0.0%	$ 34.32	4.6%	$ 33.13	0.9%
36,000 Lumen MH	$ 36.83	$ 36.83	$ -	0.0%	$ 38.51	4.6%	$ 37.17	0.9%
20,000 Lumen Mercury FL	$ 36.83	$ 36.83	$ -	0.0%	$ 38.51	4.6%	$ 37.17	0.9%
54,000 Lumen Mercury FL	$ 60.81	$ 60.81	$ -	0.0%	$ 63.58	4.6%	$ 61.36	0.9%
27,500 Lumen Sodium FL	$ 35.68	$ 35.68	$ -	0.0%	$ 37.30	4.6%	$ 36.00	0.9%
50,000 Lumen Sodium FL	$ 48.94	$ 48.94	$ -	0.0%	$ 51.17	4.6%	$ 49.39	0.9%
140,000 Lumen Sodium FL	$ 71.51	$ 71.51	$ -	0.0%	$ 74.76	4.6%	$ 72.16	0.9%
12,000 Lumen MH FL	$ 25.26	$ 25.26	$ -	0.0%	$ 26.41	4.6%	$ 25.49	0.9%
20,500 Lumen MH FL	$ 33.79	$ 33.79	$ -	0.0%	$ 35.33	4.6%	$ 34.10	0.9%
36,000 Lumen MH FL	$ 49.82	$ 49.82	$ -	0.0%	$ 52.09	4.6%	$ 50.27	0.9%
110,000 Lumen MH FL	$ 72.80	$ 72.80	$ -	0.0%	$ 76.11	4.6%	$ 73.46	0.9%
Anchor & Guy	$ 2.03	$ 2.03	$ -	0.0%	$ 2.12	4.6%	$ 2.05	0.9%
Conductor	$ 0.02	$ 0.02	$ -	0.0%	$ 0.02	4.6%	$ 0.02	0.9%
Pole	$ 2.03	$ 2.03	$ -	0.0%	$ 2.12	4.6%	$ 2.05	0.9%
Transformer	$ 2.03	$ 2.03	$ -	0.0%	$ 2.12	4.6%	$ 2.05	0.9%
Special Lighting (LS)								
Minimum Charge (Summer)	$ 4,407	$ 4,407	$ -	0.0%	$ 4,407	0.0%	$ 4,407	0.0%
Minimum Charge (Winter)	$ 10,178	$ 10,178	$ -	0.0%	$ 10,178	0.0%	$ 10,178	0.0%
Distribution								
Summer Energy Rate 1st Block	$ 0.1746	$ 0.1746	$ -	0.0%	$ 0.1855	6.2%	$ 0.1768	1.3%
Summer Energy Rate 2nd Block	$ 0.1369	$ 0.1369	$ -	0.0%	$ 0.1478	8.0%	$ 0.1391	1.6%
Winter Energy Rate 1st Block	$ 0.1746	$ 0.1746	$ -	0.0%	$ 0.1855	6.2%	$ 0.1768	1.3%
Winter Energy Rate 2nd Block	$ 0.1369	$ 0.1369	$ -	0.0%	$ 0.1478	8.0%	$ 0.1391	1.6%

Source: Company workpaper, Rate Design ER-2014-0351; Schedule DED-7.