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Direct Testimony

of

H. Edwin Overcast

September 2010

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OF
H. EDWIN OVERCAST
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

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**DIRECT TESTIMONY
OF
H. EDWIN OVERCAST
ON BEHALF OF
THE EMPIRE DISTRICT ELECTRIC COMPANY
BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION**

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. H. Edwin Overcast, Director, Enterprise Management Solutions, a Black & Veatch Company.

Q. WHAT IS YOUR BUSINESS ADDRESS?

A. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Schedule HEO-1 to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. I have been employed in the energy industry for over 35 years in various rate, regulatory and planning positions. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. My testimony has addressed a variety of issues including cost allocation, rate design, regulatory policy, open access and unbundling, bypass economics, forecasting, electric marginal costs, and a number of other issues. In addition, I have been a lecturer in a number of energy industry sponsored training programs including: the Edison Electric Institute Rate Fundamentals Course and the Advanced Rate Course; the American Gas Association Rate Course and the Advanced Rate School; and the Southern Gas Association Intermediate Rate Course. Specifically, I have lectured on the principles of electric cost of service for both retail and wholesale jurisdictions.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. I am appearing on behalf of The Empire District Electric Company ("Empire" or "the Company") in this proceeding before the Missouri Public Service Commission ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the development of the unbundled cost of service study and the appropriate rate design for the various electric service schedules. I refer to the cost of service study as unbundled because the functions of generation, transmission, distribution and customer have been identified separately and these unbundled components have guided the design of the rates for each class of service. The proposed rates strike a balance between the competing objectives that are in play when a regulatory authority is making determinations regarding the establishment of rates and charges for public utility service. In addition to the cost of service study, I am providing a seasonal and time of use analysis based on marginal costs that is designed to identify seasonal costs differences and the optimal definition of seasons applicable to seasonal rates.

Q. HOW IS THE TESTIMONY ORGANIZED?

A. The testimony is organized in the following sections:

Introduction

Section 1- Cost of Service

Section 2- Results of the Cost Study

Section 3- Seasonal and TOU Periods

Section 4- Residential Rate Design

Section 5- Commercial Service Rate Design

Section 6- General Service Rate Design

Section 7- Lighting Rates

Section 8- Summary and Conclusions

In addition, I am sponsoring a number of schedules contained in this testimony.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the revenue requirement be allocated using the results of the cost of service study as follows:

- For each class of service producing a return below the system average an increase no greater than 1.5 times the average
- For each class of service producing a return more than 25% above the proposed rate of return, no increase
- For each class of service producing a return between the proposed return and 125% of the proposed return an increase no greater than 50% of the average proposed increase.

I also recommend a number of changes to the Company's rates based on detailed analysis of the optimal seasonal rate. The seasonal analysis based on a normalized 2011 year demonstrates that a summer season of July and August is superior to the current four month season in terms of economic efficiency and appropriate price signals. Further, the seasonal differential is smaller than the current differences based on the cost by season. I also recommend changes in the elements of the rates including the customer charge, demand charge and energy charge as applicable for each rate schedule.

SECTION 1- COST OF SERVICE

Q. WHAT IS THE PURPOSE AND USE OF THE COST OF SERVICE STUDY?

A. There are many purposes for utility cost analysis ranging from designing appropriate price signals to determining the share of costs or revenue requirements borne by various rate classes. In this case, the cost study provides a useful guide for the allocation of the electric revenue requirements among the various rate classes.

Q. PLEASE DESCRIBE THE VARIOUS TYPES OF COST OF SERVICE STUDIES THAT MAY BE USEFUL FOR RATE DESIGN AND THE ALLOCATION OF REVENUE REQUIREMENTS.

A. In general, cost studies may be based on embedded costs or marginal cost. Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (a historical period) or the estimated book value of costs for a forecasted test year. There are other possible test years based on a combination of historical and adjusted costs and revenues. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes and between customers within a class. Marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service. Marginal cost studies are forward looking to the extent permitted by available data. Marginal cost studies are useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers. In this case, marginal costs have been used to determine the optimal seasons for rates with seasonal features and to develop optimal time of use (TOU) periods.

Q. PLEASE DISCUSS THE REASON THAT COST OF SERVICE STUDIES ARE USED.

A. Cost studies are a basic tool of ratemaking. They represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs[1]. In addition, utility costs may be fixed or variable costs[2]. Finally, utility costs exhibit significant economies of scale[3]. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, either marginal or embedded, requires an understanding of the operating characteristics of the utility system.

[1] Common costs occur when the fixed costs of providing service to one or more classes or the cost of proving multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[2] Fixed costs do not change with the level of output while variable costs change directly with the utility output. Most non-fuel related utility costs are fixed and do not vary with changes in load.

[3] Scale economies result in declining average cost as output increases and marginal costs below average costs.

Further, as discussed below different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. PLEASE DISCUSS THE ECONOMIC THEORY UNDER-PINNING COST ANALYSIS.

A. Economic theory holds that efficient prices equal short-run marginal cost. For an electric utility characterized by economies of scale, setting prices based on marginal costs will not produce adequate revenues because marginal cost is below average cost. Stated another way, utilities are declining cost industries. Given the nature of rate cases, it is often hard to understand the concept of a declining cost industry particularly when rates increase because of new capacity additions. The fact that rates increase as a result of higher costs does not change the fact that from an economic perspective the electric industry is a declining cost industry. To understand this issue requires an understanding of the long-run average cost curve (LRAC). The LRAC assumes that all input prices are fixed as is the available technology. In the real world, we have inflation and changing technology as well as policy changes that impact cost. As a result costs rise over time as the LRAC shifts upward with inflation.

Q. PLEASE CONTINUE.

A. Utilities must be allowed to collect revenues that are adequate to provide the utility a reasonable opportunity to earn a return of and on the assets used to serve customers. Since the utility could not achieve that objective with prices based on marginal cost, economists developed a theoretical approach to reconciling marginal cost based prices with the revenue constraint. The theory of Ramsey pricing resolves the revenue adequacy issue by suggesting that raising prices above marginal cost in relation to the inverse of the price elasticity of the product or service provided results in the least societal welfare loss from prices that differ from marginal cost. This means that under Ramsey pricing (a form of differential pricing), customers' rates are increased above marginal cost until the rates produce adequate revenues. Increases are largest for those customers or classes of service whose demand is most inelastic.

To implement Ramsey pricing requires, among other things, estimates of customer or class price elasticity. Since estimating price elasticity for electric service is complex, utilities developed other practical methods for resolving the revenue adequacy issue. Alternatively, the theory of multi-part pricing suggests that it is possible to recover average costs from infra-marginal prices while setting the marginal price equal to marginal cost. Thus, the use of block rates permits efficient prices while recovering total revenue requirements. Other examples of efficiency based rates includes the concept of fixed variable rate design where fixed cost recovery occurs through fixed charges (since fixed costs do not contribute to marginal cost) and variable charges recover variable costs.

The theory of pricing also requires a theory of class or service cost allocation. However, the existence of joint and common costs makes any allocation of costs arbitrary. This is theoretically true for any of the various marginal or embedded cost methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy free so long as the price exceeds marginal cost but is less than stand alone costs (SAC). Indeed all of this theory provides useful insight to the regulatory process where, as a practical matter, costs must be allocated between classes of service and within classes of service. For example, if the process of cost allocation results in rates that exceed stand alone costs for some customers, prices must be set below the stand alone cost but above marginal cost to assure that those customers make the maximum practical contribution to common costs. SAC plays a role in addressing issues such as discounting rates to retain customers with competitive service options elsewhere. SAC represents an element of the allocation process for cost studies and is an alternative to the concept of fully allocated costs. Unlike other more conventional allocation methods SAC relies on estimated replacement costs rather than actual costs.

Q. IF ANY ALLOCATION OF COMMON COST IS ARBITRARY, HOW IS IT POSSIBLE TO MEET THE PRACTICAL REQUIREMENTS OF COST ALLOCATION?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Under the traditional embedded cost allocation, the process follows three steps: functionalization, classification and allocation.

This three step process underlies the determination of cost causation. By identifying the functions of utility service-production or generation, transmission, distribution and customer for electric service- and the costs of these functions, the foundation is laid for classifying costs based on the factors that cause the utility to incur these costs-energy, demand and customers. The development of allocation factors by rate schedule or class uses principles of both economics and engineering to develop allocation factors appropriate for different elements of costs. Embedded cost allocation may provide the class costs associated with actual test year revenue requirements or simply the relationship between costs and revenues for an historic period by customer class.

Q. PLEASE DISCUSS THE ELEMENTS OF MARGINAL COST ANALYSIS.

A. Marginal cost studies, in contrast to embedded cost studies, focus on the change in costs associated with a small change in output. Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs include the following:

1. The relationship between historic and prospective costs reflects changes in technology.
2. Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement, particularly where economies of scale are significant.

3. The underlying impacts of inflation on prospective costs differ from past costs.
4. Additions to capacity are lumpy and as a result utilities optimal additions often include more capacity than the marginal change in load.

To estimate marginal cost, the first step requires determining the change in cost associated with the consumption of one more kWh. Essentially, marginal costs require an understanding of the system planning process. Often, however, the planning process does not provide all of the information necessary to develop marginal cost estimates.

To the extent that marginal costs differ by hour or by season, the development of system dispatch models provides the basis for this determination. These models determine how system resources are dispatched to meet load based on the operating characteristics of the various generating units on the system and any transmission or other constraints such as must take provisions that might require a unit to operate out of merit order. The dispatch also reflects the heat rate curves of each thermal generating unit. Using the dispatch model, it is possible to determine the change in costs associated with a change in output or the marginal energy cost.

The second step in the determination of how marginal cost relates to the change in capacity requirements as measured by the change in demand. For an electric system, load diversity increases as the point of measurement moves from the customer through the system up to generation. Thus it is necessary to estimate how capacity demand influences the costs for distribution, transmission and generation. At the customer premise, the system must be sized to meet the maximum demand of the customer- the customer's non-coincident peak. The cost of these local facilities is customer specific and is appropriately allocated on a per customer basis. This includes the meter, service line, transformer and the minimum system component of lines. The capacity requirements for the portion of the distribution system related to demand must reflect the non-coincident demands on the system since delivery must satisfy the local demands that may not be coincident with the system peaks for a number of reasons. Initially, the capacity requirements for transmission reflect the coincident demand for the transmission system as measured by loads on transmission. Transmission loading includes not only the customer loads but also the loads imposed for services such as energy moved through the system, exports (moving energy for sale off the system), and imports (purchasing energy from outside the system). For transmission it is important to consider the overall level of reliability given the operation of the system by the regional operator.

As the result of conservation programs sponsored by the utility and other incentives for conservation, capacity is freed up on the existing delivery system and much of the new capacity requirements are related to connecting new customers. This means that the marginal cost of distribution is small relative to the costs for infrastructure replacement and reliability investments.

SECTION 2- RESULTS OF THE COST STUDY

Q. PLEASE DISCUSS THE APPLICATION OF THE THREE STEPS IN THE COST OF SERVICE STUDY.

A. Cost are functionalized and classified in the study based on data from the Uniform System of Accounts (USOA). The cost study uses two types of allocation factors: external factors and internal factors. *External* allocation factors are based on direct knowledge from data in the utility's accounting and other records. Generation is functionalized to production accounts and allocated based on both an external capacity and energy allocation factor depending on the nature of the account. Transmission costs are functionalized to transmission FERC accounts and are assigned by an external transmission allocation factor. Another example of an external allocation factor is allocation of distribution system costs, both the demand and customer components. The costs of distribution facilities are known and assigned directly to the distribution function as substations, poles, towers and fixtures, overhead and underground conductors, transformers, service lines and meters. Once assigned to distribution, the poles and conductors are allocated using the minimum system as the external allocation factor. *Internal* allocation factors are based on some combination of external allocation factors, previously directly assigned costs, and other internal allocation factors. For example, the allocation factors for property insurance costs are based on plant investment amounts assigned to each function; therefore it is necessary to compute the amount of plant by function before property insurance costs can be assigned. Both external and internal allocation factors are used in each of the functional and classification steps outlined below.

Q. PLEASE DESCRIBE THE RESULTS OF THE ALLOCATION PROCESS AS APPLIED TO THE USOA.

A. The follow section outlines by FERC account the allocation of costs to each function and classification.

A. <u>Intangible Plant (FERC Accounts 301-303): is</u> functionalized and classified based on plant.

B. <u>Production Plant and Expenses:</u>

1. <u>Plant:</u> Production Plant (FERC Accounts 310-359) is functionalized to Supply and classified to Demand.

2. <u>Expense:</u> Production Expenses Non-Fuel (FERC Accounts 500-554 Except 501 & 547) are functionalized, and classified based on FERC Accounts 310-359. Production Expenses Fuel (FERC Accounts 501, 547, 555-557) are functionalized to Supply, and classified to Energy.

C. <u>Transmission Plant and Expenses</u>

1. <u>Plant:</u> Transmission Plant (FERC Accounts 350-359) is functionalized to Transmission, and classified to Demand.

2. <u>Expense:</u> Transmission Operation & Maintenance (FERC Accounts 560-571) are functionalized, and classified based on FERC Accounts 350-359.

D. <u>Distribution Plant and Expenses</u>

1. Distribution Plant (FERC Accounts 360-373)

a. Poles (FERC Account 364) are functionalized to Dist 13kV (Primary) and Secondary based on a Company estimate. The estimate was that 85% of the distribution Poles support the Primary system and that 15% of the distribution poles support secondary system. The Primary Poles are classified as either Customer or Demand. The Customer component percentage was determined by taking the ratio of the cost of replacing the present distribution system verses replacing the total system with only the minimum size pole. The minimum size Pole is 40-foot based on an Empire requirement for primary circuits. As a result of employing the minimum-size concept, 64% of the Primary Poles were classified as customer related and 36% Primary Demand related. The Secondary Poles are classified to Customer.

b. Overhead Lines (OH Lines) (FERC Account 365) are functionalized to Dist 13kV (Primary) and Secondary based on the number of miles of line for the Primary and Secondary distribution system. The result was that the 84% of the distribution OH Line are on the Primary system and that 14% of the OH Line on the Secondary system. The Primary OH Lines are classified as either Customer or Demand. The Customer component percentage was determined by taking the ratio of the cost of replacing the present distribution system verse replacing the total system with only the minimum size OH Line. The minimum size OH Line is 4-4 ACSR based on Company installation records. As a result of employing the minimum-size concept, 31% of the Primary OH Lines were classified as

Customer related and 69% Primary Demand related. The Secondary OH Lines are classified to Customer.

c. Underground Conduit (FERC Account 366) is functionalized to Dist 13kV (Primary) and Conduit are classified to Customer.

d. Underground Lines (UG Lines) (FERC Account 367) are functionalized to Dist 13kV (Primary). The Primary UG Lines are classified as either Customer or Demand. The Customer component percentage was determined by taking the ratio of the cost of replacing the present distribution system verse replacing the total system with only the minimum size UG Line. The minimum size UG Line is 1/0 AA concentric neutral jacketed 15kV cable based on Company installation records. As a result of employing the minimum-size concept, 34% of the Primary UG Lines were classified as customer related and 66% Primary demand related.

e. Line Transformers (FERC Account 368) are functionalized to Distribution Secondary. The Line Transformers are classified as either Customer or Demand. The customer component percentage was determined by taking the ratio of the cost of replacing the present distribution system versus replacing the total system with only the minimum size Line Transformer. The minimum size Line Transformer is 15kVA based on Company installation records. As a result of employing the minimum-size concept, 60% of the Line Transformers were classified as customer related and 40% Primary demand related.

f. Services (FERC Account 369) are functionalized to Secondary Distribution, and then classified to Customer.

g. Meters (FERC Account 370): Meter-Plant is functionalized to Onsite, and then classified to Customer.

h. Station Equipment (FERC Account 362) is functionalized to Primary Distribution, and classified to Demand.

i. Structures and Improvements (FERC Account 361) are functionalized to Primary Distribution, and classified to Demand.

j. Land and Land Rights (FERC Accounts 360) are functionalized to Primary Distribution, and classified to Demand.

k. Installed on Customers Premise (FERC Accounts 371) are functionalized to Secondary Distribution, and classified to Customer.

l. Street Lighting (FERC Accounts 373) is functionalized to Secondary Distribution, and classified to Customer.

2. Distribution Expenses (FERC Accounts 580-599)

a. Distribution Operation Expenses (FERC Accounts 582-587) are functionalized and classified based on there related FERC Accounts.

b. Operation Supervision Expenses (FERC Account 580) are functionalized and classified based on distribution Primary and Secondary labor.

c. Distribution Rents (FERC Account 589) are functionalized and classified based on other distribution plant accounts.

d. Distribution Maintenance Expenses (FERC Accounts 591-597) are functionalized and classified based on there related FERC Accounts.

e. Maintenance Supervision Expenses (FERC Account 590)) are functionalized and classified based on distribution primary and secondary labor.

j. Miscellaneous Maintenance Expenses (FERC Account 598) are functionalized and classified based on other distribution plant accounts.

F. General Plant (FERC Accounts 389-399 is functionalized and classified based on labor.

G. Depreciation Reserve (FERC Account 108) is functionalized and classified based on their corresponding gross plant values.

H. Other Rate Base Items: These various accounts are functionalized and classified based on labor or plant.

I. Customer Accounts Expenses

1. Meter Reading Expenses (FERC Accounts 902) are functionalized to Onsite and classified to Customer.

2. Customer Records & Collection Expense (FERC Accounts 903) are functionalized Onsite and classified to Customer.

3. Uncollectible Account Expenses (FERC Account 904)are functionalized and classified based on revenue requirements.

J. Customer Service & Information Expenses

1. Call Center Expenses (FERC Account 908) are functionalized Onsite and classified to Customer.

2. Customer Assistance Expense (FERC Account 910) is functionalized Onsite and classified to Customer.

K. Administrative and General Expenses (Accounts 920-939 are identified in two groups: labor related, and plant related. Labor related expenses are functionalized and classified according to labor in each function. Plant related expenses are functionalized and classified according to plant in each function.

L. Depreciation and Amortization (FERC Accounts 403-404 are functionalized and classified the same as the allocation of Accumulated Depreciation and Amortization.

M. General Tax, Payroll and Real Estate Tax: Payroll taxes were functionalized and classified based on labor. Real Estate Taxes were functionalized and classified based on Plant.

O. Income Taxes were functionalized and classified based on revenue.

P. Revenue and Other Revenue were functionalized and classified based on revenue requirements and allocated based on actual revenues collected from each class in the Test Period.

Q. PLEASE DESCRIBE THE COST OF SERVICE EXHIBIT ATTACHED TO THE TESTIMONY.

A. The results of the cost of service study are contained in five schedules as follows:

- Schedule HEO-1 consists of 22 pages and represents the results of the class cost of service study for the test year. Each page contains an account description or label for the accounting data indicating the category of cost. The total amount for each account is also provided. Class rate of return and net income may be found on pages 17 and 18.
- Schedule HEO-2 consists of 9 pages and provides the summary of account functionalization.

- Schedule HEO-3 consists of 24 pages and summarizes the classification and allocation of the accounts.
- Schedule HEO-4 consists of 148 pages and provides the allocation of each account by classification and by rate class.
- Schedule HEO-5 consists of 32 pages and provides a summary of the allocation factors by account and function.

Q. PLEASE DISCUSS THE ALLOCATION FACTOR FOR PRODUCTION PLANT.

A. The capital cost of production plant is determined based on the type of plant that minimizes the cost of meeting the expected system load duration curve. To determine the optimal system resource mix, planners recognize that both the capital cost and the energy cost play a role. Baseload plants typically have higher capital costs and lower energy costs because that produces the lowest total cost for meeting baseload or year round production requirements. Peaking plants have the lowest capital cost but have the highest energy costs. Since baseload plants operate for many hours of the year, it is reasonable to develop an allocation methodology that recognizes that it is average demand that contributes to the portion of load best served by baseload plants. It is the peak load that contributes to the selection of peaking capacity as the preferred generation technology. Further, in between the peaking capacity and baseload capacity there are intermediate units that are economic to run for more hours than a peaking unit but fewer hours than a baseload unit. Based on these considerations, the use of the average and excess demand (AED) cost allocation methodology is the most appropriate cost allocation method under these conditions. I have developed the AED method based on a review of the total demand on system capacity, not simply the system load demand. This is an important distinction because load is not the only demand placed on capacity. Generation capacity must also be maintained and based on certain conditions may not be fully available to serve load. Also, unplanned outages place a demand on the available capacity. Thus the demand on system capacity is the sum of load demand to serve customers, the scheduled outage demand for maintenance, the forced outage demand for unplanned outages and the demand that occurs because of weather or operating issues that limit capacity to less than the full output of the generator. Based on the full demand on capacity, the appropriate AED allocation factor consists of average demand (energy divided by 8760 hours) and the excess demand based on twelve coincident peaks (12 CP). AED/12CP reflects cost causation for the system based on all of the operating characteristics of the system. The excess demand component is allocated on the class non-coincident peaks (NCP).

Q. PLEASE DISCUSS THE ALLOCATION OF TRANSMISSION PLANT.

A. Transmission Plant is allocated based on 12CP. The use of 12 CP reflects the use of Transmission Plant on a monthly basis. Absent significant differences in monthly loading of the transmission system such as high summer peaks and low winter peaks, a 12 CP allocation factor is consistent with the design and use of Transmission Plant. For Empire, winter and summer peaks are very close in terms of load.

Q. PLEASE DISCUSS THE ALLOCATION OF DISTRIBUTION PLANT.

A. Distribution Plant includes substations, poles and wires, transformers, meters and services. In addition, Distribution Plant includes lighting. The allocation of Distribution Plant requires that the investment be classified as demand or customer. In addition, it is important to understand the role of scale economies in distribution service when allocating costs and designing rates for delivery service. The cost of distribution facilities declines per kWh consumed for any given level of demand. For example, the cost of facilities such as transformers has a lower per unit of demand cost for higher demands. The following table provides data for a range of transformers that may be installed for residential customers and the cost per kVa of each size of transformer.

Table 1

Cost per kVa of Transformer Capacity

Single Phase Transformer	Installed Cost	Cost per kVa
10 kVa	$1038	$103.80
15 kVa	$1034	$68.93
25 kVa	$1244	$49.76
50 kVa	$1725	$34.50

The above table illustrates the cost per kVa of transformer capacity declines dramatically as the size of the transformers increases. For customers with an NCP below 10 kW, the unit cost is over twice as much as for customers served off a 25 kVa transformer. Since a 10 kVa transformer is the minimum size installed, smaller customers served off this transformer cost more to serve per unit of NCP than do larger customers served off larger transformers. The implications for cost of service are that customers with higher NCP may actually have lower total costs that smaller customers. Compare two customers as follows: first, a customer with central air conditioning and an electric water heater with an NCP of 10 kVa and second, an all electric customer with an NCP of 17 kVa. Further assume that the all electric home is in a subdivision where three homes are served off a 50 kVa transformer. The total cost of transformer capacity is about $587 each for the all electric homes and $1038 for the smaller demand customer's home. When recovering the cost from each customer, it is necessary to take into account the relative load factor of each customer since fixed costs are recovered volumetrically. The typical all electric home has a higher load factor based on NCP than the typical non all electric home, resulting in an even lower cost per kWh for the all electric home. In addition, the all electric home has a much higher coincident peak (CP) load factor when the system peaks in the summer like it does for Empire. On a CP basis, the rates for the all electric customer should be substantially lower than the other customers. This is the fundamental basis for declining block residential rates and demonstrates that such rates are cost based.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COST OF SERVICE STUDY.

A. The following table provides a summary of the calculated returns by rate class for the listed rate classes.

Table 1

Rate of Return by Rate Class

Rate Class		Class Return
Res Gen	RG	5.1%

Comm	CB	7.9%
Comm Space Heating	SH	7.8%
GP- TEB	TEB	9.2%
GP	GP	10.0%
Large Power	LP	5.6%
Power Feed Mill and Grain Elevator	PFM	20.9%
Special Contract	SC-P	3.3%
Municipal Lighting	SPL	13.0%
Private Lighting	PL	25.0%
Special Lighting	LS	-0.6%

Q. PLEASE DISCUSS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF THE PROPOSED INCREASE BASED ON THE COST OF SERVICE STUDY.

A. Based on the results of the cost of service study, I recommend that the following rate classes have no increase allocated to the class:

1. Feed Mill and Grain Elevator- Class PFM
2. Municipal Lighting- Class SPL and
3. Private Lighting- Class PL.

The three classes receiving no rate increase account for just less than 1.6% of revenue. For all other rate classes, I recommend an increase in rates based on the concept of moving all classes toward the cost of service. The overall percentage increase requested by the Company is 9.19%. Therefore, I suggest that no class receive an increase greater than 13.8% or less than 4.6%. Since it is not possible to have each actual increase equal to the expected percentage and produce the overall target revenue, I have used the proposed increase provisions for each class of service except the residential class. For the residential class, the increase represents the residual of the rate increase dollars after applying the described adjustments to all other classes.

SECTION 3- SEASONAL AND TIME OF USE PERIODS

Q. PLEASE DISCUSS THE BASIS FOR A SEASONAL DIFFERENTIAL IN ELECTRIC RATES.

A. A seasonal differential is appropriate where costs differ significantly by season of the year. The seasonal differential recognizes that system operating conditions and therefore costs may differ in a predictable pattern that needs to be reflected in rates to improve efficiency. There are a number of reasons for cost differences to arise based on seasons of the year. The existence of seasonal cost differences is most often driven by the mix of fuels used to produce energy to meet the peak demands of the system and the intensity of those peak demands. Where the maximum demand on capacity of the system differs significantly, there may also be seasonal capacity cost differentials. It is important in analyzing seasonal cost differences to understand the total demand on the resources of the system. Customer load does not represent the total demand on the capacity resources of the system. The demand on system resources also includes scheduled outages, unit de-ratings and unit forced outages. These latter three demands generally represent a smaller total impact than load but must also be considered in evaluating seasonal differentials related to a capacity cost component.

Q. HAVE YOU REVIEWED THE SEASONAL COST DIFFERENTIAL FOR THE COMPANY?

A. Yes. I have analyzed the seasonal energy and capacity cost differences using the normalized loads and the costs for calendar year 2011. Based on that data, the current seasonal cost differential is too large and does not reflect the actual cost differences for the test year. In addition, the seasonal definition used in current rates is suboptimal.

Q. PLEASE EXPLAIN THE ANALYSIS USED TO DETERMINE THE SEASONAL COST DIFFERENTIAL.

A. The fundamental consideration of the seasonal differential is to minimize the cost variance within a season and to maximize the variance of costs between seasons. The seasonal energy costs differential calculation uses an analysis of the average of the hourly marginal costs for the test year. The analysis begins by establishing certain practical constraints on the development of the differential. The practical constraints include the following: a season must consist of at least two consecutive months; a maximum number of four seasons is permitted; all days within a calendar month are treated equally; and seasons must begin at the beginning of a calendar month and end at the end of a calendar month. The second step of the analysis determined the variance of costs within a group of possible seasons and the variance between the seasonal options. The ratio of the cost variance between seasons and the cost variance within seasons that is the largest determines the best seasonal combination. This ratio is designated as the F-statistic. (One use of the F-statistic is to compare the variances of populations, hence the use of the term in this context.)

Q. PLEASE DESCRIBE THE RESULTS OF THE ANALYSIS.

A. Summary results are illustrated in Schedule HEO-6. As the schedule illustrates, the most appropriate seasonal combination based on energy costs consists of a peak season made up of the months of July and August and an off-peak season for the remainder of the year. This combination of months produces the largest value for the F-statistic. Under the current tariff, the summer season consists largely of the billing months of June through September. This option results in a substantially lower F-statistic and therefore does not represent the most appropriate costing period for seasonal rates. The difference in marginal cost between the seasons represents the maximum seasonal differential in the energy cost component of the rate. Schedule HEO-7 illustrates the differences in hourly cost for the summer months compared to the average of the winter season marginal costs.

Q. PLEASE DESCRIBE THE APPROPRIATE DIFFERENTIAL IN THE SEASONAL COMPONENT OF THE ENERGY CHARGE.

A. The energy charge differential should reflect the difference in marginal costs between the seasons adjusted for the losses associated with the voltage level of service. The differential between the peak season (defined as the calendar months of July and August) and the off-peak season (the other ten months of the year) at the generation bus is $ 0.0077 per kilowatt-hour. This value is divided by one minus the loss factor applicable to the particular service schedule to produce the maximum seasonal differential. Thus, there is no justification for the current differentials in the various rate schedules.

Q. WHAT IS THE IMPLICATION OF THIS ANALYSIS FOR THE SEASONAL DIFFERENTIAL IF THE CURRENT PEAK SEASON IS MAINTAINED?

A. The continuation of the current peak season for purposes of rate stability would produce an even lower season differential based on the results of my analysis. On the basis of marginal cost the resulting differential is $0.0033 divided by the loss adjustment factor or less than one cent per kilowatt-hour. At this level, the seasonal differential becomes inconsequential to consumers. For this reason, there is no compelling rational for maintaining the current seasonal definition.

Q. HOW DOES THE ISSUE OF MARGINAL PRODUCTION CAPACITY COST IMPACT THE SEASONAL DIFFERENTIAL?

A. Given the current capacity situation and the annual demands on that capacity, there does not appear to be a seasonal capacity cost differential. The maximum winter and summer peak loads are within a 100 MW difference. The total demand on capacity falls in a reasonably narrow range around the mean demand on capacity. Schedule HEO-8 presents the comparison graphically. The maximum differentials occur in shoulder months of May and October. In other months the difference is less than 100 MW, leading to the conclusion that production capacity costs tend to be uniform. When the total demand on capacity is considered, there is no justification for a seasonal allocation of production capacity costs.

Q. SHOULD THERE BE A SEASONAL DEMAND DIFFERENTIAL BASED ON TRANSMISSION AND DISTRIBUTION CAPACITY COSTS?

A. No. Transmission capacity costs are allocated on 12 CP recognizing the use and characteristics of the transmission system. Since costs are allocated on all months a uniform charge for transmission is appropriate. For distribution, the driving factor for cost is NCP regardless of when it occurs. Thus there is no need for a seasonal demand charge differential. Rather, it is appropriate to use the facilities demand charge to recover the distribution costs for demand billed customers and to use the fixed charge component of non-demand rates to reflect distribution costs as well as customer costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO THE SEASONAL DIFFERENTIAL.

A. The current differential is too large and needs to be reduced for all classes of customers where a seasonal differential is part of the rate schedule. The current peak season is not optimal and for that reason alone, it is necessary to redefine the summer and winter seasons to a more optimal basis. Therefore, I recommend that the summer season be defined as bills rendered for two consecutive billing cycles on or after the 15th of July. It is also important, in my view, to redesign the rates with a smaller differential and to increase fixed charges, as discussed below, to reflect the significant fixed cost component of the rates. Therefore, I recommend the following: The maximum differential for each class be set at the loss-adjusted level using the generation cost differential of $0.0077 per kilowatt-hour given the limits of rate design.

With respect to the demand charge, I recommend that the production and transmission demand charges be set to recover the allocated demand costs for those services based on dividing the class revenue requirement by the billing demand determinants. I recommend continuation of the facilities charge to recover the distribution related revenue requirement.

Q. PLEASE PROVIDE THE LOSS ADJUSTED SEASONAL DIFFERENTIALS BASED ON THE LOSS ADJUSTED VALUE.

A. The following table provides the loss adjusted differentials for each voltage level.

Voltage Level of Service	Energy Loss Factor	Seasonal Differential	Loss Adjusted Differential
Transmission	1.02578	$0.0077	$0.0079
Primary Substation	1.03464	$0.0077	$0.0080
Primary	1.05142	$0.0077	$0.0081
Secondary	1.07633	$0.0077	$0.0083

Q. PLEASE DISCUSS THE OPTIMAL TOU RATES FOR EMPIRE.

A. It is my understanding that there are no TOU customers on the regular rate and the only TOU provisions applicable to any customer is under the Praxair special contract. The optimal TOU periods based on the analysis using the principles discussed- minimizing the variance within a period and maximizing the variance between periods- the optimal TOU period is from 7:00 AM until 10:00 PM weekdays year round. Under a more complex form of the TOU rate with different non- contiguous seasons such as winter, summer and shoulder seasons and allowing for on-peak, shoulder and off peak TOU periods in the winter and shoulder seasons, the optimal hours for the winter and shoulder seasons may differ. However, with no customers on the rate and the added complexity for metering and billing it does not seem useful to develop a more complicated version of the rate at this time.

SECTION 4- RESIDENTIAL RATE DESIGN

Q. PLEASE DESCRIBE THE CURENT RESIDENTIAL RATE.

A. The current residential rate consists of a customer charge and a flat energy charge in the summer and a declining block charge in the winter. Despite the declining block feature, these energy charges are substantially higher than the energy cost incurred by the Company. This is not unusual for energy only rates that must also recover fixed costs associated with production, transmission and distribution in the energy charge. Nevertheless, it is important to recognize that volumetric recovery of these fixed costs imposes a risk on the Company that it will not recover the level of revenue authorized by the Commission as the result of weather or conservation. Rates must provide the Company with a reasonable opportunity to earn the allowed return given the impact of circumstances beyond the reasonable control of the Company. Recovery of substantial fixed costs in volumetric rates does not provide that opportunity.

Q. HOW DO YOU PROPOSE TO IMPROVE THE CURRENT RESIDENTIAL RATE?

A. The current residential rate needs to recover more fixed costs in the customer charge and less in the energy charges. As a result, I propose to significantly increase the customer component of the rate in the new Customer Access Charge. I also propose to collect the remainder of the revenue requirement in the summer charge and the first block of the winter charge with an appropriate seasonal differential in the first block. While it is not practical to redesign the rate fully at this time because of the customer impacts, it should be the long-term goal of the Commission to incorporate the principles of rate design contained in other rates such as the distribution demand charge into the residential rate via graduated Customer Access Charges that recover not only customer costs but fixed distribution costs as well.

Q. HAS THE COMPANY PROVIDED BILL COMPARISONS FOR THE PROPOSED RATES?

A. Yes. Company witness Ms. Kelly Emmanuel has provided the typical bill comparisons for the present and proposed residential rates.

Q. ARE THERE OTHER ADVANTAGES OF IMPROVING THE RESIDENTIAL RATE DESIGN?

A. Yes. Improving the residential rate design also improves the efficiency of the rate with respect to net metering. Under the net metering rider, a customer that produces more electricity than the customer uses during certain periods within the billing month is effectively credited the current rate as compensation for the excess energy. The current rate includes the recovery of fixed production, transmission and distribution costs that the utility cannot avoid and that exceed marginal cost. Therefore, there is an excess payment for the customer's energy. Currently, the excess payment is over twice the actual avoided costs contained in the Cogeneration Purchase Rate Sschedule CP. Reducing this excess payment sends more appropriate price signals to consumers.

Q. IS THERE EVIDENCE THAT HIGHER FIXED CHARGES ARE APPROPRIATE FOR RESIDENTIAL RATE DESIGN?

A. Yes. Higher fixed charges represent an efficient rate design and have broad acceptability among customers. For example, based on data for the Missouri customer owned electric cooperatives, the average fixed charge for residential customers is over $22.00 per month. Since customers own and regulate the cooperative, the use of this charge represents a customer approved charge. Of the 40 cooperatives in Missouri, 15 have fixed charges of $25.00 per month or higher and 30 have charges of $20.00 per month or higher. With higher fixed charges, rates are more reflective of the costs incurred and more efficient.

SECTION 5- COMMERCIAL SERVICE RATE DESIGN

Q. PLEASE IDENTIFY THE COMMERCIAL SERVICE RATES EMPLOYED BY THE COMPANY.

A. The Company has the following commercial service rates:

- Commercial Service–Schedule CB
- Small Heating Service- Schedule SH and
- Total Electric Building Service- Schedule TEB.

Each of these three schedules is discussed below.

Q. PLEASE DISCUSS THE DESIGN OF SCEHDULE CB.

A. As with the residential rate, I recommend that the allocated increase begin by substantially increasing the new Customer Access Charge of the rate. In addition, I recommend that the remainder of the increase be recovered in the summer and first winter block rates with a seasonal differential in the first block while the second winter block remains the same.

Q. PLEASE DISCUSS THE DESIGN OF SCHEDULE SH.

A. The proposed changes for Schedule SH follow the process for Schedule CB with the exception of a slight decrease in the winter tail block.

Q. PLEASE DISCUSS THE DESIGN OF SCHEDULE TEB.

A. For Schedule TEB, I recommend that the customer charge be replaced by a Customer Access Charge and that charge be increased substantially for both regular and interval meter customers. The Facilities Demand Charge should be set to recover the distribution demand costs allocated to the rate. The remainder of the increase is allocated to the new uniform demand charge component to produce the revenue requirement.

SECTION 6- GENERAL SERVICE RATE DESIGN

Q. PLEASE IDENTIFY THE GENERAL SERVICE RATE SCHEDULES EMPLOYED BY THE COMPANY.

A. The Company has the following general service rate schedules:

- General Power Service- Schedule GP
- Large Power Service- Schedule LP
- Special Transmission Service- Schedule ST and
- Feed Mill and Grain Elevator Service- Schedule PFM.

Each of these schedules is discussed below.

Q. PLEASE DISCUSS THE RATE DESIGN CHANGES FOR SCHEDULE GP.

A. As with all of the rates, I recommend redefining the summer season consistent with the development of the optimal season and seasonal differential. I recommend that the customer charge be replaced by the Customer Access Charge and that charge be set at $100 per month for regular customers and $220.80 per month if an interval meter is required. I recommend that the Facilities Demand Charge be designed to recover the distribution demand costs allocated to the rate in the cost of service study. The remainder of any revenue shortfall should be recovered in the demand charge for both winter and summer.

Q. PLEASE DISCUSS THE RATE DESIGN CHANGES FOR SCHEDULE LP.

A. Consistent with other changes to the commercial and industrial rates, I recommend that (1) the seasons be redefined, (2) the customer charge be replaced by the Customer Access Charge and be set at $400 per month and (3) the Facilities Demand Charge be set to recover the Distribution Costs from the cost of service study. The remaining revenue requirement should be recovered in the demand charge. I also recommend changing the Metering Adjustment provision to reflect the latest loss factors for energy as follows: for service metered at secondary voltage the 1.0198 adjustment factor should be increased to 1.0237 and for service metered at transmission voltage, the adjustment factor should be increased from 0.9742 to 0.9756.

Q. PLEASE DISCUSS THE CHANGES FOR SCHEDULE ST.

A. It is my understanding that there are no customers served under this rate schedule. I recommend that the Company reserve the design of this rate until such time as one or more customers opts for this rate as a result of having no target revenue requirements to use to design the schedule. In the event that a customer with demand greater than 6000 KW seeks service based on TOU principles, I recommend that the Company develop a rate using the results from the TOU study discussed above and the potential customers revenue requirements. Alternatively, I recommend that some form of real time pricing may also offer an opportunity to serve this type and size of customer. At this time, the rate will have no charges included in the rate.

Q. PLEASE DISCUSS THE RATE DESIGN CHANGE FOR PRAXAIR.

A. I recommend that the Praxair rate be redesigned with a $1,000 per month customer charge, the facilities charge be eliminated and any rate increase authorized in this case be recovered in the demand charge. I recommend no change in the interruptible credit.

Q. PLEASE DISCUSS THE RATE DESIGN CHANGES FOR SCHEDULE PFM.

A. Although this rate is closed to new customers, it is important for the rate to reflect costs. I propose the customer charge be replaced by the Customer Access Charge and that charge be set at $40 per month for both seasons. The remaining revenue requirement would be recovered in the KWH charges. Further, I recommend that if a customer terminates service for any reason the premise will no longer be eligible for service under this schedule.

SECTION 7- LIGHTING RATES

Q. WHAT CHANGES DO YOU RECOMMEND FOR LIGHTING RATES?

A. I recommend that the lighting rates per lamp be increased by the percentage increase applicable to the lighting service class.

SECTION 8- SUMMARY AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS RELATED TO COST OF SERVICE AND RATE DESIGN.

A. The most appropriate method for cost allocation is the average and excess 12 CP method proposed herein. Based on the results of the cost of service study, there should be a concerted effort to increase the rates for the Rate LP and special contract customer up to the full rate of return. It may even be appropriate to do so even quicker than I recommend above. Given the magnitude of the rate increase and the rate design changes required, it may also be appropriate to gradually redesign rates over time to a more economically sound rate structure and to consider rate decoupling to provide the Company a reasonable opportunity to recover its fixed costs. A thorough review of the rate design independent of a rate case proceeding may be appropriate since such a filing would allow the Commission the opportunity to consider the allocation and design of rates without the added complexity of an increase in revenue requirements.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

AFFIDAVIT OF H. EDWIN OVERCAST

STATE OF MISSOURI)
) ss
COUNTY OF JASPER)

On the 24 day of September, 2010, before me appeared H. Edwin Overcast, to me personally known, who, being by me first duly sworn, states that he is Director of Enterprise Management Solutions Black & Veatch and acknowledged that he has read the above and foregoing document and believes that the statements therein are true and correct to the best of his information, knowledge and belief.

H. Edwin Overcast
H. Edwin Overcast

Subscribed and sworn to before me this 24 day of September, 2010

Sherri J. Blalock
Notary Public

My commission expires: Nov. 16, 2010

SHERRI J. BLALOCK
Notary Public - Notary Seal
State of Missouri
Commissioned for Newton County
My Commission Expires: November 16, 2010
Commission Number: 06969626