Ameren Exhibit 16.0E (Revised)

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 09-0306 – 09-0311

REVISED DIRECT TESTIMONY

OF

LEONARD M. JONES

SUBMITTED ON BEHALF OF

CENTRAL ILLINOIS LIGHT COMPANY
d/b/a AmerenCILCO

CENTRAL ILLINOIS PUBLIC SERVICE COMPANY
d/b/a AmerenCIPS

ILLINOIS POWER COMPANY
d/b/a AmerenIP

THE AMEREN ILLINOIS UTILITIES

August 2009

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Submitted On Behalf Of

The Ameren Illinois Utilities

I. INTRODUCTION

A. Witness Identification

Q. Please state your name.

A. My name is Leonard M. Jones. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis MO 63103.

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

A. I am employed by Central Illinois Light Company as a Manager of Rates and Analysis. In this capacity I am filing testimony on behalf of the Ameren Illinois Utilities (AIUs).

Q. Please describe your educational background and relevant work experience.

A. See my Statement of Qualifications, attached as an Appendix to this testimony.

B. Purpose, Scope and Identification of Exhibits

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my testimony is to establish the AIUs recommended electric rate design and provide the associated analysis. Specifically, I will testify concerning: (a) the AIUs' overall pricing objectives and the various considerations in developing the tariffs included in this filing; (b) revenue allocation among the various customer classes; (c) the proposed rate design, including unbundling of the Distribution Tax; (d) the estimated level of revenue resulting from the implementation of the proposed electric delivery service tariffs; (e) alternative rate designs closely adhering to cost of service study results; (f) the AIUs' proposed tariffs; and (g) proposed changes to the Supply Cost Adjustments.

Q. Please summarize the conclusions of your direct testimony.

As detailed below, I conclude

- Existing rate classes should be retained.
- Movement to rates that recover each class' revenue requirement at equal return should be constrained to limit bill impacts
- The Distribution Tax should be unbundled from base delivery rates and recovered separately through the Tax Additions tariff
- Residential rate design (DS/BGS-1) should be modified to begin the process of correcting for imbalances in intra-class DS and BGS rates
- Small general service rates (DS/BGS-2) should be modified similar to the approach used for DS/BGS-1
- Customer and Meter Charges should be combined on customer bills into a single Fixed Monthly Charge, but remain separately stated in DS tariffs

- DS-3 and DS-4 Distribution Delivery Charges should eventually be moved or kept closer together, but doing so in this proceeding would produce class increases to DS-4 greater than the limits set forth in the revenue allocation methodology
- DS-5 Fixture Charges should be moved closer together among the AIUs

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

Ameren Exhibit 16.1E	Analysis of DS-3 and DS-4 Rate Classes and Respective Distribution Delivery Charges
Ameren Exhibit 16.2E	Revenue Allocation For Delivery Service
Ameren Exhibit 16.3E	Proposed Distribution Tax Section to Tax Additions Tariff
Ameren Exhibit 16.4E	Summary Of Cost Based Meter Charges for DS-1 and DS-2
Ameren Exhibit 16.5E	Development of Residential DS-1 and BGS-1 Charges
Ameren Exhibit 16.6E	Current And Proposed Unit Charges For Delivery Service
Ameren Exhibit 16.7E	Residential Frequency Distribution of Proposed Rate Increases
Ameren Exhibit 16.8E	Residential Bill Impact Comparisons At Various Usage Levels: General Use and Homes Heated Using Electricity
Ameren Exhibit 16.9E	Development of Non-residential DS-2 and BGS-2 Charges
Ameren Exhibit 16.10E	Non-residential DS/BGS-2 Frequency Distribution of Proposed Rate Increases

Ameren Exhibit 16.11E	Summary Of DS-3 and DS-4 Distribution Delivery Charges
Ameren Exhibit 16.12E	Results of Incremental Cost Study for Lighting Fixtures
Ameren Exhibit 16.13E	Current and Proposed Unit Charges for DS-5 Lighting Service
Ameren Exhibit 16.14E	Jurisdictional Operating Revenue at Present And Proposed Rates
Ameren Exhibit 16.15E	Cost-based Revenue Allocation and Rates

I am also sponsoring the electric tariffs being filed for each of the AIUs (Schedule E-1). The proposed tariffs also include Rider VGP, which will be discussed separately by Ameren witness Mr. Robert Mill.

Q. Does this testimony address any gas or gas rate design issues?

A. No, although I have had several consultations with Ameren witness Mr. Paul Normand, the AIU witness providing the gas cost of service study and rate design. I reviewed Mr. Normand's findings and conclusions, and provided general insight and guidance regarding the AIUs desire to move toward cost-based rates, but at a pace that does not cause undue customer bill impacts. This is similar to the approach used for electric revenue allocation.

II. <u>RATE OBJECTIVES AND RATE CLASSES</u>

Q. What were some of the AIUs' goals and objectives in the development or design of Delivery Service ("DS") rates?

A. The principle pricing objective used to guide the development of tariffs focused on designing and considering rates that are cost based, but also taking into account bill impacts to customers, while providing the AIUs with a reasonable opportunity to earn their authorized rate of return. We also acknowledge the current rates were last set in October 2008. When these rates go into effect, customers will have had only approximately 1 ½ years experience with the rates. Thus, we are mindful of the principles of rate continuity and stabilization. Further, tariffs should be understandable to the extent practical and easily administered by AIU personnel.

Also, the AIUs also seek to maintain synchronized DS and Basic Generation Serivce ("BGS") rates, that is rate classes within the DS rate paradigm matching the rates in the BGS rate structure. There is also the desire to maintain unified pricing (uniformity) where possible. The Illinois Commerce Commission ("Commission") has encouraged and approved tariff uniformity in the past for AmerenCIPS, AmerenIP and AmerenCILCO among DS tariffs and gas tariffs.

Q. What are the proposed classes in this case?

A. The AIUs are proposing to retain use of five service classifications as follows:

Service Class	Delivery Service	Availability
Residential Service	DS-1	All residential
Small General Service	DS-2	Non-residential up to 150 kW
General Service	DS-3	Non-residential, 150 kW up to 1,000 kW
Large General Service	DS-4	Non-residential 1,000 kW and greater
Lighting Service	DS-5	All photo-eye controlled lighting

These service classifications are synchronous with the AIUs' power supply or BGS tariffs.

Q. Why is it important?

A. Again, as I mentioned above, we believe it important that customer see some logic in matching of the DS rate under which they take service to the "comparable" BGS rate. Customers understand generally the nature of their classification—residential commercial and industrial, and subclasses within these categories. Here, we are attempting to strive for the same consistency and understanding.

Q. Have the Ameren Illinois Utilities studied the propriety of developing a DS-3 subclass for customers with demands at 400 kW up to 1,000 kW?

A. Yes. That study has been combined with an analysis exploring the differences in Distribution Delivery Charges applicable to DS-3 and DS-4 customers. The conclusion reached is that the existing rate classes are appropriate, and the difference in comparable Distribution Delivery Charges for DS-3 and DS-4 can be set at a level that recognizes the differences in monthly demands for each class through the year and the use of the Reactive Demand Charge within DS-4. See Ameren Exhibit 16.1E. The ECOSS results provided in Ameren witness Ms. Karen Althoff's testimony show that in general, revenue responsibility for DS-4 should be increased by an amount greater than that for DS-3. As discussed later, requiring each class to contribute an amount of revenue closer to their respective cost of service will likewise bring the Distribution Delivery Charges for DS-3 and DS-4 closer.

III. <u>REVENUE ALLOCATION</u>

Q. Did you analyze a Class Cost of Service Study in preparing your recommended rate design?

A. Yes, in the formulation of my recommended revenue allocation and rate design, I relied upon the Class Cost of Service Study Prepared by Ms. Althoff.

Q. How do the AIUs propose to recover the overall revenue requirement from each class in this case?

A. The AIUs propose to move toward rates that recover each class' revenue requirement assuming an equalized rate of return. For DS-1 through DS-4, the amount of movement has been constrained to limit rate impacts. The revenue allocation approach used for DS-5 customers is based on an effort to move DS-5 fixture prices closer together for each of the AIU's, a step the AIU's were required to consider. As described later, this process results in a slight rate decrease for AmerenIP and AmerenCILCO DS-5 customers, and an increase for AmerenCIPS customers.

Q. Please describe the methodology for constraining the rate change to the various rate classes.

A. For Rates DS-1 through DS-4, the change in rates has been limited to no more than 125% of the overall average change in rates for the respective AIUs, excluding the impact of the Distribution Tax expense. This constraint permits an increase in delivery services, excluding the distribution tax, of 21.8% for AmerenIP, 19.5% for AmerenCIPS, and 23.5% for AmerenCILCO. The Distribution Tax is discussed in more detail in the next section.

For DS-5 (Lighting Service), steps were taken to create more Fixture Charge price uniformity among the AIUs'. Rate changes for this class were deemed too great to implement full uniformity at this time, thus movement was constrained so that the change in rates results in a limit of about $1/fixture change to the HPS 100 W fixture price for the respective AIUs. Additional details pertaining to pricing are discussed in the description of the DS-5 lighting rate design changes. The result of the DS-5 revenue allocation methodology is revenue reductions of approximately $1.97 million, $1.62 million, and $60,000 reallocated to each respective AIUs' DS-1 through DS-4 classes. This step is shown on Ameren Exhibit 16.2E in columns 5 and 6. Page 1 shows the values for AmerenIP, page 2 shows the determination for AmerenCIPS, and page 3 provides the calculation for AmerenCILCO. The overall revenue allocation methodology reallocates this excess revenue amount pro-rata based on each class' present revenue contribution. The reallocation results in less than a 1.3 percentage point shift in rate change responsibility overall and to any one class.

Q. Why is the Distribution Tax singled out in the proposed revenue allocation methodology?

A. The distribution tax has been included as an expense in the previous total revenue requirement calculation. The cost study used to develop prices for rates effective January 2, 2007 allocated the distribution tax expense based on utility plant assets rather than kWh. The annual distribution tax is assessed to the AIUs based on the quantity of retail electricity delivered in Illinois, making it clearly driven by kWh sales and not based on plant assets (discussed more in the next section). The DS-3 and DS-4 classes were allocated approximately 11% and 8% of total plant in those cases, respectively, yet were responsible for approximately 12% and 43% of total kWh sales, respectively. In comparison, the residential class was allocated approximately 56% of total plant in those cases, yet was responsible for approximately 30% of total kWh sales. Thus, in this proceeding, the DS-4 class is receiving a much greater share of the distribution tax expense responsibility, which is greatly influencing the cost of service results shown by Ms. Althoff. Removing the influence of the Distribution Tax in the revenue allocation methodology ensures that each class pays its fair share of the expense. Moreover, for some large non-residential customers, the Distribution Tax will be as great as or larger than the entire delivery services amount due. For example, a DS-4 customer served from supply lines greater than 100 kV, 10 MW of peak demand and a 50% load factor would pay a delivery services bill of about $3,432 at AmerenCILCO, $3,662 at AmerenCIPS, and $3,862 at AmerenIP under present rates while the Distribution Tax for that same customer would be about $3,240 at AmerenCILCO, $4,644 at AmerenCIPS, and $4,968 at AmerenIP. This represents a sharp percentage increase in delivery service costs, but viewed against a total bill including power costs, the Distribution Tax represents about 2% to 3% of the total electric bill (assuming 4.5 ¢/kWh cost for power and energy supply).

Q. What is the percentage effect of the Distribution Tax on each class?

A. Including the Distribution Tax within the percentage change calculations for base rate increases has a relatively minimal impact for the DS-1 class but a much greater impact on DS-4. For DS-1, the impact ranges by AIUs from 2.5% to 4%. For DS-2, the Distribution Tax represents 4% to 5.5% of the total rate change. For DS-3, the impact ranges from 5.3% to 8%, while for DS-4, the range is from 34% to 38%.

Q. The percentage changes due to the Distribution Tax for the DS-4 class raise the proposed base rate increase for DS-4 from 19.5% to 23.5%, to a combined increase of 57% to 60%. Do increases in this range present a bill impact concern to DS-4 customers?

A. In general, bill impact concerns are indeed a concern and this is in part why the AIUs have proposed to limit increases to any one class to no more than 125% of the average increase excluding the effect of the Distribution Tax. The total increases to DS-4 would have approached 100% if not for the proposed revenue allocation limitation. That said, the percentage amounts should also be kept in perspective. In a previous answer, an example was provided showing that application of the Distribution Tax to a customer served from a +100 kV supply line voltage would experience a 100% increase, but only a 2% to 3% overall increase to their total bill including power priced at 4.5 cents/kWh. As will be shown later, the Distribution Tax amounts are 0.138 ¢/kWh for AmerenIP, 0.129 ¢/kWh for AmerenCIPS, and 0.090 ¢/kWh for AmerenCILCO.

Q. Are there other reasons why a constrained revenue allocation is appropriate at this time?

A. The rates of the Ameren Illinois Utilities have undergone a significant transition from 2006 bundled rates to tariffs in effect today. In 2006, the Commission established cost based Delivery Services rates by following the results of an embedded cost of service study, and directed the AIU's to set rates to recover revenue sufficient to provide an equalized rate of return from each class. In 2007, both DS and BGS rates were modified in the "rate redesign docket" to address severe customer impacts. Those changes took effect in December 2007 (BGS) and January 2008 (DS). The most recent delivery service rate case applied an across-the-board change to rates, rather than a revenue allocation method that more closely utilized cost of service results, primarily out of concern for creating disproportionate bill impacts. Those changes were implemented on October 1, 2008. Assuming this proceeding is suspended for an 11 month period, these rates will not go into effect until May 2010. Thus, approximately 2.5 years will have passed since the rate redesign case, and nearly 3.5 years since DS rates had been established in direct alignment with the results of a cost of service study. Applying a constrained revenue allocation resumes the practice of making steps toward cost-based rates, while helping to minimize the potential for disproportionate bill impacts to customers.

Q. How are each of the rate classes for the AIU's impacted by the constrained revenue allocation approach?

A. For AmerenIP, both DS-3 and DS-4 reach the limit of 21.77%, while DS-1 and DS-2 are allocated 18.8% and 19.2% increases, respectively. For AmerenCIPS, the DS-4 reaches the limit of 19.5%, DS-3 is allocated a 12.4% increase, and DS-1 and DS-2 rate class has been limited to 16.5% and 13.9% increases, respectively. For AmerenCILCO, both DS-2 and DS-4 reach the limit of 23.5%, while DS-1 and DS-3 were allocated increases of 17.9% and 19.2%, respectively. The proposed revenue targets for each class are shown in Ameren Exhibit 16.2, pages 1-3. The final increase without the Distribution Tax is shown in columns 23 and 24. The total increase including the effect of the Distribution Tax is shown on page 5.

IV. <u>DISTRIBUTION TAX</u>

Q. What is the Distribution Tax assessed to public electric utilities?

A. The Distribution Tax is described in the Public Utilities Revenue Act, 35 ILCS 620. It is my understanding it replaced the "invested capital tax" when the Customer choice Act was passed in December 1997. The Distribution Tax is levied on electric utilities based on the total amount of energy delivered in a year at differing rates for up to seven different kWh sales blocks. The kWh sales blocks and effective rate for each of the AIU's is shown in the following table.

Ameren Illinois Utilities
Determination of Distribution Tax for Test Year
Using Distribution Tax Rates per Public Utilities Revenue Act - 35 ILCS 620

Test Year Annual kWh Sales		
AmerenIP	AmerenCIPS	AmerenCILCO
18,146,843,099	12,490,935,371	6,416,298,418

	kWh Block	cents/kWh	AmerenIP	AmerenCIPS	AmerenCILCO
First	500,000,000	$ 0.031	$ 155,000	$ 155,000	$ 155,000
Next	1,000,000,000	$ 0.050	$ 500,000	$ 500,000	$ 500,000
Next	2,500,000,000	$ 0.070	$ 1,750,000	$ 1,750,000	$ 1,750,000
Next	4,000,000,000	$ 0.140	$ 5,600,000	$ 5,600,000	$ 3,382,818
Next	7,000,000,000	$ 0.180	$ 12,600,000	$ 8,083,684	$ -
Next	3,000,000,000	$ 0.142	$ 4,260,000	$ -	$ -
Over	18,000,000,000	$ 0.131	$ 192,364	$ -	$ -
Total			$ 25,057,364	$ 16,088,684	$ 5,787,818
Average Distribution Tax Rate			**$ 0.00138**	**$ 0.00129**	**$ 0.00090**

Q. Are the Ameren Illinois Utilities proposing a different way to account for and recover the Distribution Tax?

A. Yes. Rather than include the Distribution Tax as an expense item within the revenue requirement, the AIU's propose to separately apply the Distribution Tax as a component within the Tax Additions tariff. Each customer would be assessed the estimated average tax rate for their respective AIUs based on their kWh consumed, much in the same manner that the State excise tax is levied. The AIUs' propose that the Distribution Tax and any applicable State excise tax amounts be combined for bill presentment purposes, yet accounted for and separately tracked within the AIUs' billing system.

Q. Why should the Distribution Tax be recovered through a separate Tax Additions provision rather than as an addition to the Distribution Delivery Charge for each rate class?

A. The Distribution Tax is a cost that is clearly energy related, yet Rates DS-3 and DS-4 do not contain any energy related charges. However, the State excise tax is presently applied to DS-3 and DS-4 customers' bills based on kWh consumed. Rather than create an energy based charge within DS-3 and DS-4, the proposed Tax Additions tariff has been modified to also include the Distribution Tax. The proposed Distribution Tax also permits a consistent application of a rate component across each rate class.

Q. How will the Distribution Tax tariff provisions operate?

A. The Distribution Tax provides for an annual determination of an average rate for each AIUs based on forecast kWh information. Differences between the amount of Distribution Tax paid to the State and tax revenue collected will be included in the second subsequent year. Additionally, any refund amount received from the Illinois Department of Revenue for the previous tax period will be included in the calculation for the tax rate in the second subsequent year. For example, the tax revenue collected for year 2010 will be known in January 2011, and any tax refund amount for 2010 will be received by December 2011. All known tax costs and revenues will be incorporated within the development of the Distribution Tax rate for the year 2012. A copy of the proposed Distribution Tax language within the Tax Additions tariff has been provided for reference as Ameren Exhibit 16.3E.

Q. Assuming that this case concludes near the middle of 2010, how do you propose to account for tax "revenue" and "costs" for the part of the year where the Distribution Tax is not in effect?

A. The AIUs' propose the initial rate for 2010 be calculated assuming it was in effect for the full year, and further assume that existing delivery service rates recover an identical amount. Essentially, the kWh sales from the beginning of 2010 up to the effective date of this tariff will be credited at the determined rate. The first reconciliation under this tariff will include amounts actually collected under the Distribution Tax provision plus the estimated amount from the first part of the year.

Q. Has the proposed Distribution Tax changed your presentation of proposed rates?

A. Yes. In prior Delivery Service cases, excise taxes were assumed to remain constant between present and proposed rates. As such, taxes were not explicitly recognized in revenue allocation or rate design. In order to show an "apples to apples" comparison, the effect of Distribution Tax is shown within the proposed revenue allocation and bill comparison exhibits.

V. RECOMMENDED RATE DESIGN

Q. Please describe the tariffs that constitute bundled rates.

A. Rates for electric service may be differentiated into three categories that when added together, constitute fully bundled service. The first set of rates pertains to the delivery of electricity through wires or other assets owned by the AIUs and under the jurisdiction of the Commission. Delivery service costs will be recovered from customers under the proposed Delivery Service tariffs filed in this docket. The second set of rates pertains to transmission service provided by or procured by the AIUs on behalf of its customers, under the jurisdiction of the Federal Energy Regulatory Commission. Transmission service costs will continue to be recovered from customers under Rider TS. The third set of rates applies to the provision of electric energy. Customers may take power from the AIUs' through Riders BGS, RTP, or HSS, as applicable. Customers that elect to take electric energy needs from a third party supplier will not be subject to the power supply provisions of Riders BGS, RTP or HSS, or the transmission service provisions under Rider TS. These customers' transmission services will presumably be arranged by their suppliers.

Q. What is the basic rate structure proposed for delivery service pricing?

A. The Ameren Illinois Utilities propose to maintain the rate design convention in effect today. In general, the proposed Delivery Service rates contain separate rate components for meter, customer, and distribution delivery. Meter and Customer Charges are recovered through a fixed monthly charge per meter or per bill. Distribution Delivery Charges are assessed on per kWh (smaller customers) or per kW (larger customers) basis.

Q. Please explain the methodology used to develop the Delivery Service rates that the Ameren Illinois Utilities are proposing in this proceeding.

A. In general, the Ameren Illinois Utilities seek to maintain the pricing structure previously approved. For DS-1, the AIUs propose to reinstate uniform Meter Charges and Customer Charges. For DS-2 through DS-4, the Ameren Illinois Utilities propose to maintain uniform Meter and Customer Charges. The Ameren Illinois Utilities propose to also maintain uniform Transformation (for both DS-3 and DS-4) and Reactive Demand (DS-4 only) Charges. The Distribution Delivery Charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. As a result of the rate redesign case, the Distribution Delivery Charge applicable to DS-1 and DS-2 customers is also seasonally differentiated. The AIUs propose to keep a seasonally differentiated charge, and implement a declining block rate for the non-summer Distribution Delivery Charge. The reduced non-summer, tail block Distribution Delivery Charge will be offset by increases to tail block BGS prices such that the total variable price that customers pay will be slightly greater than today. The changes to both DS and BGS rates will be "revenue-neutral" within the DS and BGS categories of service. That is, there will be no actual BGS dollars transferred to DS cost recovery, or vice versa. (Residential rate design initiatives will be discussed at length in the next section of my testimony.)

For DS-5, steps have been taken to ensure Fixture Charges are more uniform among the AIUs as suggested in the prior rate case order (Docket Nos. 07-0585 et. al. (cons.)). Individual Fixture Charges are priced based on the results of an incremental cost of service study, scaled to produce revenue equal to the total embedded cost of service for all of the AIUs DS-5 classes, but final prices are adjusted to limit bill impacts to customers both within the DS-5 class and DS-1 – DS-4. Achieving uniform Fixture Charges by following the AIUs proposed method indicate that further decreases to AmerenIP DS-5 Fixture Charges are needed. Conversely, further increases are necessary for AmerenCIPS DS-5 Fixture Charges. The proposed Fixture Charges for AmerenCILCO are set at the uniform price target level.

Q. Why are there separate Meter and Customer Charges in the DS rates?

A. The Meter Charge is separately stated because customers are permitted to choose a Meter Service Provider (MSP) other than the Ameren Illinois Utilities. Customers who take service from a MSP do not pay the AIUs' Meter Charge. The Meter Charge recovers the cost of the meter, associated recurring meter expenses, and meter reading. Examples of costs recovered in the Customer Charge include current and potential meter transformers, service line and administrative costs of servicing the account.

For bill presentation purposes, the AIUs propose that the Customer and Meter Charges be combined and shown on customer bills as "Fixed Monthly Charge". The Meter Charge was unbundled nearly 10 years ago, and to date there have been no active MSPs in the AIUs territory (nor am I aware of any within the State). There are no MSPs presently registered to offer service to AIUs customers (as of the date of this filing). Separately stating a charge makes sense when a customer has a reasonable opportunity to act on the bill information. For example, showing the energy charge for each kWh consumed provides information to customers, that greater or lower kWh usage will result in greater or lower bills, or that perhaps a third party supplier could offer a better price. Today, the Meter Charge does not provide any such information to customers. It is a charge that can only be avoided if there is a MSP willing to provide service.

Q. If the Commission approves your proposal to combine the Customer and Meter Charges for bill presentation purposes, would that preclude customers from

avoiding the Meter Charge in the event a MSP began providing service to customers in the AIUs service territory?

A. No. If a MSP were to begin service within the AIUs service territory, customers receiving service from such MSP would not be assessed the Meter Charge and the bill would revert to simply assessing a Customer Charge.

Q. Has the Commission previously allowed the Customer and Meter Charges to be combined on Delivery Services tariffs?

A. Yes. The residential Delivery Service tariffs for AmerenIP showed a combined customer and meter charge until January 2, 2007.

A. <u>METER CHARGES</u>

Q. Please explain how you developed proposed Meter Charges for DS-1 and DS-2 for each of the AIUs.

A. Metering service has been unbundled to facilitate the possibility that a MSP could offer competitive service to customers. As such, a separate cost of service study was conducted by Ms. Althoff that determined the total meter cost allocated to each DS rate class, as directed in Docket No. 99-0013. Proposed Meter Charges were set uniformly among the AIUs, and designed to recover the metering cost of service for each class of the AIUs. For example, the Meter Charge for DS-2 is the same for similarly situated customers in AmerenCILCO, AmerenCIPS, and AmerenIP service areas. Presently the DS-1 Meter Charges for each AIUs are different. Prior to the last delivery services case, these charges were uniform between the AIUs. In the last DS case, the ICC expressed a desire to return to uniform Meter Charges in the future (Final Order Docket. Nos. 07-0585 et. al. (cons.), p. 280). The results of the uniform Meter Charges are shown in Ameren

Exhibit 16.4E. Present Meter Charges are uniform among DS-2, DS-3, DS-4 and DS-5 customers of the AIUs.

Q. How were proposed Meter Charges for DS-3 and DS-4 established?

A. The AIUs propose to retain current voltage differentiated Meter Charges for DS-3 and DS-4. Setting Meter Charges equal to a strict cost value would result in a reduction to the charges. The reduction in Meter Charge revenue would in turn place upward pressure on the DS-3 and DS-4 $/kW Distribution Delivery Charges, further widening the gap between DS-3 and DS-4 $/kW prices. As discussed in Ameren Exhibit 16.1E, steps should be taken to close the gap between DS-3 and DS-4 $/kW charges where appropriate. Setting the Meter Charge equal to the strict cost of service results run counter to that objective and should not be applied at this time.

Q. Why is it appropriate to maintain uniform Meter Charges?

A. While each of the AIUs have unique historical accounting records and resulting valuations of metering plant and related expenses, the incremental cost of new metering facilities for each of the AIUs is about the same. The AIUs business practices continue to conform, and over time one would expect costs to likewise converge.

B. <u>RESIDENTIAL SERVICE</u>

Q. What are the tariff components and charges for DS-1, residential Delivery Service?

A. The DS-1 tariff contains monthly Meter and Customer Charges and a Distribution Delivery Charge for all kWh delivered in a month. The Distribution Delivery Charge is seasonally differentiated and is priced higher in the summer months (June – September) and lower in the eight non-summer months. This seasonally differentiated Distribution

Delivery Charge was implemented on January 1, 2008 and approved in the rate redesign docket. The rate redesign docket addressed significant bill impacts experienced by customers, with a special focus on those that use electricity to heat their homes using electricity, also referred to throughout my testimony as space-heat customers, electric heat customers or all-electric customers. This special category of residential customers is rooted in legacy bundled tariffs of AmerenIP and AmerenCIPS that were in effect prior to January 2, 2007.

Q. Did the rate redesign docket also restructure power prices available to residential customers?

A. Yes.

Q. Did the Commission provide any guidance in the last DS rate order on residential rate structures to consider in this proceeding?

A. Yes. The Commission stated as follows:

> "In considering a move towards rates based on the cost of service, AIUs should take into account alternative rate structures for the all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. Market-based dynamic prices may have the overall effect of reducing the electric bills of all-electric classes of customers while at the same time ending the explicit subsidy that was designed to accomplish the same end." (Final Order 07-0585 et. al. (cons.), p. 281)

> "An analysis of the effect of dynamic market-based prices for the all-electric sub-class of residential customers would give the Commission valuable insight as to its potential benefits as the utility tries to meet those important and some times mutually exclusive, objectives in the next rate case. In its cost of service analysis, AIUs' electric utilities should develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial." (Final Order 07-0585 et. al. (cons.), p. 282)

Q. Please provide an overview of the changes made to residential power prices in the rate redesign case.

A. Rider BGS prices available to residential customers (BGS-1, a component of Rider BGS – Basic Generation Service) were realigned to reinstate a special electric space-heat discounted power rate for customers that previously received a special discounted rate prior to January 2, 2007 for AmerenIP and AmerenCIPS. (January 2, 2007 was the date fully bundled legacy rates expired and unbundled rates took effect.) For AmerenCILCO customers and AmerenCIPS customers served under rates formerly applicable to Union Electric Company's Illinois customers (Metro-East customers), there was no special discounted rate available to only electric space-heat customers prior to January 2, 2007. Instead, the rate structures for those two service areas contained non-summer declining block rates applicable to all customers. Electric space-heat customers in those service areas received the benefit of discounted rates, but were not separately identified for billing purposes. Similarly, the rate redesign case provided discounted BGS-1 prices for non-summer use over 800 kWh for all customers in those service territories. Doing so leveled the bill impacts experienced by customers, and dramatically lowered impacts to customers that heat their homes using electricity.

Creating discounted non-summer tail block rates for AmerenIP (space-heat only), AmerenCIPS (space-heat only), AmerenCIPS Metro East (all customers), and AmerenCILCO (all customers) required adjustments to other BGS prices to compensate. One adjustment was that prices for the first 800 kWh of non-summer residential use was increased by about 1.0 ¢/kWh for AmerenCILCO and AmerenCIPS, and by about 0.37 ¢/kWh for AmerenIP. These initial block prices are uniform for space-heat and non-space heat customers alike, but differ slightly by AIUs. Prior to the rate redesign adjustment, the initial block charge for each AIUs was nearly uniform at about 7.6 ¢/kWh.

Q. Are the marginal prices for space-heat use competitive with market prices for power and energy?

A. No. The disparity in pricing can be seen when comparing the non-space heat (NSH) prices in the table below for AmerenCIPS and AmerenIP to the electric space heat prices. The marginal BGS-1 power prices for all residential customers using more than 800 kWh are provided in the table below.

BGS-1 Purchased Electricity Charges Effective June 1, 2009

		CIPS-SH	CIPS-NSH	CIPS-ME	CILCO	IP-SH	IP-NSH
Non-Summer							
Over 800		**$0.02367**	**$0.05104**	**$0.00992**	**$0.02334**	**$0.00885**	**$0.04856**

As shown, AmerenIP's space-heat customers, and all AmerenCIPS-ME customers experience a marginal rate of less than 1 ¢/kWh. The price for AmerenCIPS (Space Heat) and AmerenCILCO customers is more than twice that amount at about 2.4 ¢/kWh. By contrast, a customer taking service under Rider PSP/RTP would have paid about 5 ¢/kWh for power in 2008, a value more in line with that for AmerenIP and AmerenCIPS NSH customers. Moreover, the weighted average price of non-summer power recently procured to serve BGS customers through the IPA was just under 5 ¢/kWh. Power market prices recently have been trading lower than they were in the first part of 2008, indicating that perhaps the hourly real-time price ("RTP") analysis represents a high-end estimate for non-summer prices for winter 2010. For example, on May 4, 2009 Platt's Power Forwards ("Platt's") reported the market for a block of Jan-Feb 2010 on-peak power at $44.75/MWh and off-peak power at $30.00/MWh. By contrast, on May 5, 2008, Platt's reported the market for a block of Jan-Feb 2010 on-peak power at $80.50/MWh, and off-peak power was reported at $48.75/MWh. Monthly RTP values for January – March 2008 averaged prices of around 6.0 ¢/kWh but by October – December began to dip to about 4.0 ¢/kWh. In all cases, the marginal cost of power is greater than the marginal BGS price generally available to customers that heat their homes using electricity.

Q. Has the cost of service for the residential sub-class of electric space-heating customers been performed?

A. Yes, the COSS performed by Ms. Althoff indicates that the residential electric heat sub-group of customers provides a DS rate of return greater than that of the non-space heat residential sub-group under present rates.

Q. Has an analysis of power prices that electric space-heat customers would pay under hourly market-based pricing been performed?

A. Yes, as mentioned earlier, the average price space-heat customers would have paid in 2008 under real-time pricing tariffs would be about 5 ¢/kWh. This price is derived by charging hourly prices actually experienced in 2008 by the average load research hourly usage for customers in the "high winter use, high summer use" load group. The price also includes the Supplier Charge (capacity and ancillary services costs) that would have applied to hourly customers in 2008.

Q. How has the analysis of RTP and the straight fixed variable (SFV) design suggested by the Commission's influenced your proposed residential rate design?

A. The AIUs' propose to move toward a SFV rate design for all residential customers and take steps to reduce the current BGS-1 subsidy offered to residential space-heat (or large use non-summer) customers. Movement to a SFV design is proposed within Rate DS-1, and compliment steps taken to reduce the amount of subsidy provided to space-heat (or large non-summer use) customers within BGS-1.

Q. What changes are you proposing for residential DS-1 rates?

A. Presently the DS-1 Customer and Meter Charges for each AIUs are different. Prior to the last delivery services case, these charges were uniform between the AIUs. In the last DS case, the ICC expressed a desire to return to uniform Customer and Meter Charges in the future (Final Order Nos. 07-0585 et. al. (cons.), p. 280). In the same dockets, the Commission also recommended that a SFV rate design be explored for residential space-heat customers. The proposed DS-1 rate design reintroduces uniform Customer and Meter Charges, and applies a SFV design that recovers approximately 39% of the total allocated delivery service revenue requirement through a combination of the Customer and Meter Charges.

The total proposed Monthly Customer and Meter Charge (Fixed Monthly Charge) is $17 for each of the AIUs. By recovering additional revenue through fixed charges, the variable Distribution Delivery Charge can be lowered, and in particular, the non-summer Distribution Delivery Charge for usage over 800 kWh. The development of DS-1 residential rates is shown in Ameren Exhibit 16.5E, page 1 for AmerenIP, page 3 for AmerenCIPS, and page 5 for AmerenCILCO.

Q. What changes are you proposing to BGS-1?

A. The changes to BGS-1 attempt to reduce the space-heat subsidy provided to customers using more than 800 kWh per month in the non-summer period. Summer BGS-1 prices remain unchanged. The development of BGS-1 residential rates is shown in Ameren Exhibit 16.5E, pages 2, 4, and 6 for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively. The methodology involves four primary steps. First, the total variable price for use over 800 kWh per month under existing rates (BGS-1 power rates and DS-1 Distribution Delivery Charges), plus 10%, is established as a target total variable charge amount for proposed rates. Second, the proposed DS-1 Distribution Delivery Charge for use over 800 kWh is subtracted from the total target variable charge from Step 1. This provides a proposed non-summer BGS-1 charge for use over 800 kWh. Third, BGS-1 revenues under existing prices are calculated. Changes to BGS prices are proposed to be revenue neutral, thus revenue under present rates provides a target revenue level for proposed rates. Fourth, proposed BGS-1 prices and revenue are determined. For space-heat customers at AmerenIP and AmerenCIPS, and all AmerenCIPS-ME and AmerenCILCO customers, the proposed price for usage over 800 kWh is increased to the target level established in Step 2. The incremental revenue from increasing those respective prices is used to offset the non-summer first block charge. An appropriate long-term goal would be to eliminate the BGS declining block structure. Each of the AIUs' proposed BGS-1 prices still have a declining block, but AmerenCIPS non-space heat customers come close to eliminating the need for a declining block. The target tail block price is within 0.138 ¢/kWh of the proposed first block price. Should the Commission choose to raise the total fixed monthly charges from that proposed by the

AIUs, the non-summer BGS block for AmerenCIPS could likely be eliminated and set to a flat rate structure.

As shown at the bottom of Ameren Exhibit 16.5E for each AIUs, the total variable price charged customers (BGS-1 plus DS-1 Delivery Charge) decrease for the first 800 kWh of non-summer use, and increase by less than 0.5 ¢/kWh for non-summer use over 800 kWh. In all cases, customers using more than 800 kWh in a non-summer period will experience a change in variable charges by no more than 10%. Present and proposed DS-1 and BGS-1 prices are summarized in Ameren Exhibit 16.6E.

Q. How did you arrive at the 10% target total variable charge increase target?

A. The 10% value appears to adequately balance total bill impact concerns to both space-heat and non-space heat customers. With a greater percentage target, large use space-heat customers would begin to experience a much greater total dollar impact. Conversely, a lower percentage target did less to remove the power subsidy paid to space-heat customers. A variable charge increase target of 10% helps ensure that the percentage increase for most space-heat customers is somewhat level, and comparable to that for the “typical” non-space heat customer using about 10,000 kWh per year.

Q. Is reducing the DS-1 Distribution Delivery Charge for use over 800 kWh consistent with the findings of the class cost of service study?

A. Yes. The cost of service results indicate that as a group, residential space-heat customers provide a greater rate of return on allocated costs than non-space heat customers. The proposed rate design reduces the relative delivery service cost burden on space-heat customers, while providing an offsetting benefit of lower BGS-1 costs to non-space heating customers.

Q. Please describe the customer impact one may expect under the proposed residential rate design.

A. Ameren Exhibit 16.7E shows expected impacts to a residential customer's total bill. The chart plots all customers that received 12 monthly bills in 2008. As one may expect, customers with little or no use will experience an increase near or equal to the Customer and Meter Charges, or $4.70 for AmerenIP, $6.54 for AmerenCIPS, and $7.81 for AmerenCILCO. The percentage increase generally falls as usage increases.

Ameren Exhibit 16.8E, pages 1-2 provides a summary of several bill calculations at various usage amounts for each AIUs. For the "typical" non-space heat customer using 10,000 kWh, the net increase in the total bill is expected to be about 8.2%, 5.5%, 6.0% and 5.8% or an average monthly amount of $8.05, $4.95, $5.38 and $5.36 for AmerenIP, AmerenCIPS, AmerenCIPS-ME and AmerenCILCO, respectively. A space-heat customer using 18,000 kWh per year could expect a net increase in the total bill of about 7.9%, 5.4%, 5.6% and 5.5% or an average monthly amount of $10.61, $6.92, $6.72 and $7.38 for AmerenIP, AmerenCIPS, AmerenCIPS-ME and AmerenCILCO, respectively.

Q. Do you have suggestions how DS/BGS-1 prices could be adjusted should the Commission decide to adopt a different movement toward a SFV rate design?

A. Yes. The proposed rate design attempts to balance the desire to reduce intra-class subsides between space-heat and non-space heat customers, while ensuring that bill impacts are within a manageable dollar or percentage amount. A reduction in the proposed Fixed Monthly Charge should be accompanied with an increase in the proposed non-summer tail block Distribution Delivery Charge. If the proposed non-summer tail block Distribution Delivery Charge is indeed raised, non-summer tail block BGS-1 charges would also remain closer to existing below-market levels (unless the constraint of limiting the change to total tail block non-summer variable charges to 10% is relaxed). Decreasing the Fixed Monthly Charge without a corresponding increase to the Distribution Delivery Charge places upward pressure on prices required for the summer and initial block non-summer Distribution Delivery Charges. (Summer and initial block non-summer Distribution Delivery Charges would need to be increased in order to achieve the targeted DS-1 revenue requirement.)

Conversely, an increase to the proposed Fixed Monthly Charge may be accompanied with a decrease to the non-summer tail block Distribution Delivery Charge, although such move is not imperative. An increase to the proposed Fixed Monthly Charge from the level recommended by the AIUs, while not adjusting the proposed non-summer Distribution Delivery Charge further downward, would reduce the summer and non-summer initial block variable Distribution Delivery Charges by an amount required to offset the additional revenue generated from the greater Fixed Monthly Charge. If instead the tail block non-summer Distribution Delivery Charge is further reduced, the BGS-1 non-summer tail block rate should be increased by an offsetting amount in accordance with the proposed rate design model. In summary, the proposed rate designs involve trade-offs between fixed and variable rate components, and between variable DS prices and BGS prices, all of which must be addressed in a coordinated fashion if the Commission modifies the proposed rate design.

C. SMALL GENERAL SERVICE

Q. What are the tariff components and charges for DS-2, the Small General Service non-residential electric service tariff for the Ameren Illinois Utilities?

A. Service under DS-2 is generally available to non-residential customers with demands up to 150 kW. Similar to DS-1, the small general service tariff contains monthly Meter and Customer Charges and a Distribution Delivery Charge component for kWh delivered in a month. Similar to DS-1, the DS-2 Distribution Delivery Charge was also seasonally differentiated in the rate redesign docket. The proposed Meter and Customer Charges are differentiated between customers served at secondary voltage level, and metering at all other voltage levels. The proposed uniform Meter Charges were previously discussed, and are shown in Ameren Exhibit 16.4E.

Q. Did the rate redesign docket also restructure power prices available to small general service customers?

A. Yes.

Q. Please provide an overview of the changes made to BGS-2 power prices in the rate redesign case.

A. Rider BGS prices available to small general service customers (BGS-2, a component of Rider BGS – Basic Generation Service) were realigned to lower bill impacts to larger non-summer use customers. Prior to rate redesign, BGS-2 prices were seasonally differentiated, but did not contain a usage block. That is, BGS-2 summer and non-summer rates were the same for all usage within the respective season. The rate redesign case added a non-summer usage block for the first 2,000 kWh and all use over 2,000 kWh for each AIUs. For AmerenCIPS, a summer usage block at the same level was also added. The rate redesign adjustments are shown in the table below:

Rate Redesign Adjustments for BGS-2			
Summer (All Voltages)	**AmerenCIPS**	**AmerenCILCO**	**AmerenIP**
All kWh		$0.02018	$0.02256
0-2000 kWh	$0.02517		
Over 2,000 kWh	$0.02000		
Non-summer (All Voltages)			
0-2000 kWh	$0.03750	$0.02318	$0.03756
Over 2,000 kWh	($0.02054)	($0.01148)	($0.01833)

Q. Please describe the proposed price changes to the small general service class.

A. The proposed rate design is shown in Ameren Exhibit 16.9E, pages 1-6. Similar to DS/BGS-1, the Customer Charge is proposed to increase by an amount to recover fixed costs beyond those traditionally considered customer-related. The AIUs' propose a Customer Charge of $15, a value just a few dollars higher than the comparable charge for DS-1 service. Similar to DS-1, the AIUs' propose to implement a DS-2 Distribution Delivery Charge block to match the BGS blocks. The proposed Delivery Charge for non-summer use over 2,000 kWh has been set at a level of approximately one-half the Delivery Charge assessed today for AmerenCIPS and AmerenCILCO. For AmerenIP, the Distribution Delivery Charge for non-summer use over 2,000 kWh was set at approximately 60% of the present charge to limit the increase needed to the summer Distribution Delivery Charge to compensate for reduced non-summer revenue.

The reduction in the non-summer Delivery Charge provides an opportunity to also re-evaluate BGS-2 non-summer charges. The sum of BGS-2 and DS-2 variable charges for use over 2,000 kWh was examined, and limited to increase by about 0.68 ¢/kWh (or

10%) for AmerenIP and 0.60 ¢/kWh (or 10%) for AmerenCIPS over present variable rates with the goal of achieving flat non-summer BGS-2 prices. As shown on pages 2, 4, and 6 of Ameren Exhibit 16.9E, the gap between the initial and tail block BGS-2 rates has been reduced significantly for AmerenIP and AmerenCIPS, and eliminated the need for a blocked BGS-2 non-summer rate for AmerenCILCO. (The total variable charge increase for AmerenCILCO DS/BGS-2 customers for use over 2,000 kWh is 4.5%.) None of the rate changes result in a total summer or non-summer variable rate increase to DS/BGS-2 customers of more than 10.4%.

Also, for AmerenCIPS, existing summer BGS initial and tail block prices are within 0.5 ¢/kWh. The proposed BGS-2 summer prices for AmerenCIPS eliminate this small differential, making AmerenCIPSs' BGS rate structure similar to present summer BGS-2 prices for AmerenIP and AmerenCILCO.

Q. Please describe the customer impacts one may expect under the proposed DS/BGS-2 rate design.

A. Ameren Exhibit 16.10E shows expected impacts to a small general service customer's total bill for each AIUs. The chart plots all customers that received 12 monthly bills in 2008. As one may expect, customers with little or no use will experience an increase equal to the Customer and Meter Charges, or approximately $9.93 per month. The percentage increase moves lower as customer usage increases.

Q. BGS-2 also contains prices for customers taking service at Primary and High Voltage delivery voltages. How will those prices be affected?

A. The present BGS-2 prices at those voltages are proposed to change by the same percentage as the secondary delivery voltage prices. The following table shows what those values should be:

Percent Change Secondary Delivery Voltage	AmerenIP	AmerenCIPS	AmerenCILCO
Summer - First 2,000 kWh	0.0%	-2.5%	0.0%
Summer - Over 2,000 kWh	0.0%	3.2%	0.0%
Non-Summer, First 2,000 kWh	-21.2%	-20.6%	-24.1%
Non-Summer, +2,000 kWh	23.8%	23.9%	19.2%

Proposed Rates Primary Delivery Voltage	AmerenIP	AmerenCIPS	AmerenCILCO
Summer - First 2,000 kWh	$ 0.07729	$ 0.07814	$ 0.07523
Summer - Over 2,000 kWh	$ 0.07729	$ 0.07804	$ 0.07523
Non-Summer, First 2,000 kWh	$ 0.07310	$ 0.07408	$ 0.06099
Non-Summer, +2,000 kWh	$ 0.05505	$ 0.05344	$ 0.06006

Proposed Rates High Voltage Delivery Voltage	AmerenIP	AmerenCIPS	AmerenCILCO
Summer - First 2,000 kWh	$ 0.07619	$ 0.07708	$ 0.07414
Summer - Over 2,000 kWh	$ 0.07619	$ 0.07690	$ 0.07414
Non-Summer, First 2,000 kWh	$ 0.07219	$ 0.07317	$ 0.06011
Non-Summer, +2,000 kWh	$ 0.05363	$ 0.05201	$ 0.05869

Q. Does your proposed DS/BGS-2 rate design have any impact on competitive supply choices for customers?

A. Perhaps. The rate redesign case artificially decreased charges to larger use BGS-2 customers, and this price reduction to larger use BGS-2 customers could make competitive offers to a customer more difficult for an alternative retail electric supplier. Nevertheless, the proposed rate design attempts to flatten BGS-2 prices, and thus level the competitive attractiveness of serving small non-residential general service customers.

Q. Should the Commission decide to adopt a slower or more aggressive movement toward a SFV rate design for DS/BGS-2, how should prices be adjusted?

A. Similar to DS/BGS-1 rate design, the proposed rate design attempts to balance the desire to reduce intra-class BGS-2 subsides between customers that use more than 2,000 kWh in a non-summer billing period and those that use less, while ensuring bill impacts are within a manageable dollar or percentage amount. In the event of a reduction or increase in the proposed Customer Charge, the steps to adjust DS/BGS-2 charges would be similar to those outlined for DS/BGS-1. Thus, that discussion or those steps will not be repeated.

D. GENERAL SERVICE AND LARGE GENERAL SERVICE

Q. What are the tariff components and charges for DS-3, the General Service non-residential electric service tariff for the Ameren Illinois Utilities?

A. Service under DS-3 is generally available to non-residential customers with a minimum demand of 150 kW and a maximum demand of less than 1,000 kW. Pricing components under this rate are monthly Meter and Customer Charges, a Distribution Delivery Charge, and a Transformation Charge.

Q. What are the tariff components and charges for DS-4, the AIUs' Large General Service tariff?

A. Service under DS-4 is generally available to non-residential customers with a demand equal to or exceeding 1,000 kW. Pricing components under this rate are the same as for DS-3, except DS-4 also contains a Reactive Demand Charge for customers with a supply line voltage under 100 kV.

1. METER AND CUSTOMER CHARGES

Q. Earlier you mentioned that proposed Meter Charges are identical to existing Meter Charges for DS-3 and DS-4. Are you proposing any changes to Customer Charges for DS-3 and DS-4 customers?

A. No, proposed Customer Charges are identical to existing Customer Charges.

Q. Why are you proposing to hold Customer Charges at present levels?

A. Similar to Meter Charges, the cost of service for customer components indicates that the Customer Charge could be decreased. However, a decrease to the Customer Charges would require other charges to increase by an even greater amount. Specifically, the Distribution Delivery Charges would need to increase from those proposed. Under the revenue allocation constraint proposed by the AIUs, a reduction to the Customer Charges would result in a greater increase to DS-3 Distribution Delivery Charges relative to those for DS-4, further widening the gap in that charge for those two classes. As discussed in Ameren Exhibit 16.1E, closing the gap between DS-3 and DS-4 Distribution Delivery Charges is preferential, subject to bill impact concerns. Maintaining existing Customer (and Meter) Charges does not trigger bill impacts, and does not widen the gap in Distribution Delivery Charges between DS-3 and DS-4, thus is recommended for this proceeding.

2. TRANSFORMATION CHARGE

Q. Why do the Ameren Illinois Utilities have a separately stated Transformation Charge for DS-3 and DS-4?

A. The Transformation Charge component is a price that compensates the AIUs for providing transformation of voltage from the customer's supply line voltage to the voltage used by the customer. Voltage is transformed through a transformer or substation, often dedicated to the customer. Customers who own and operate their own transformers, or rent transformation facilities from the AIUs, do not pay the separate Transformation Charge since they have made alternate arrangements for that service.

Q. How has the proposed Transformation Charge been developed?

A. The Transformation Charge is presently \$0.57/kW of a customer's maximum demand occurring in the most recent 12 monthly billing periods. The charge is identical for DS-3 and DS-4 customers for each of the AIUs. As with the Meter and Customer Charges, the AIUs propose to keep a uniform Transformation Charge. The level of the Transformation Charge is set by examining the replacement cost new (or incremental cost) of various transformation facilities. The incremental cost of transformation equipment is about \$0.75/kW (ranging from \$0.58/kW up to \$1.07/kW) and about \$1.44/kW for substations (ranging from \$1.09/kW up to \$1.90/kW). The AIU's propose a charge of \$0.65/kW, or an increase of about 14%. Proposing a greater increase to the Transformation Charge places upward pressure on the revenue credit associated with the Rate Limiter, which is discussed later. Absent the Rate Limiter provision, an increase to the Transformation Charge in line with the DS-3 and DS-4 class average of around 20% may be warranted.

Q. What is the Meter Reassignment Fee applicable only to AmerenCIPS customers?

A. An AmerenCIPS customer taking service under DS-3 or DS-4 that owns its transformer would avoid the Transformation Charge, but typically still be assessed a Meter and Customer Charge based on metering voltage on the high voltage side of the customer-owned transformer. AmerenCIPS had a past practice of installing meters on the high voltage side of customer-owned transformers. The higher Meter and Customer Charges (associated with higher voltage service) would more than offset savings realized by owning the transformer and avoiding the Transformation Charge.

The Meter Reassignment Fee provisions allow AmerenCIPS to charge customers a Meter and Customer Charge as if the customer was metered on the low end voltage of a customer owned transformer, and charge such customer a fee. This rate treatment is consistent with the Commission's recent DS Final order. Under current rates, the Meter Reassignment Fee is $85.50 per month, which is equivalent to 150 kW (the minimum demand required for DS-3 service) times the Transformation Charge of $0.57/kW. The proposed Meter Reassignment Fee maintains the relationship to the Transformation Charge, and is $97.50 per month (150 kW * $0.65/kW).

3. <u>REACTIVE DEMAND CHARGE (DS-4 Only)</u>

Q. What is reactive demand or power?

A. Reactive power, measured in kVAR, is sometimes referred to as "wasted power". When combined with "real" power, or kW, one can determine how much total power is supplied. Total supplied power is measured in kVA. Distribution planners must design delivery systems to meet a customer's expected peak kVA demand. The typical industry billing unit is the kW. Use of only the kW as the delivery service billing unit can cause a mismatch between costs to serve and delivery charges for individual customers within the class. Customers with a kVA value larger than the kW value will register a kVAR.

Q. Why is the Reactive Demand Charge limited to only those customers with a supply line voltage less than 100 kV?

A. Low power factors (or a high reactive demand relative to kW demand) can cause voltage problems on the distribution system. For lower voltage systems (under 100 kV), capacitors are often installed to correct local power factor problems. For higher voltage systems, power factor can still be a concern but the installation of distribution equipment for correction of reactive demand (power factor) on facilities over 100 kV is rare. Instead, more specialized or individualized solutions are required to address power factor problems at the 100kV or greater level. Therefore, in lieu of charging a standard rate based on capacitor costs per peak kVAR for customers over 100 kV, the AIUs directly assigns the cost of power factor correction measures, if any, to the customer if it has a power factor less than 95% lagging or leading. This provision has been in place for each of the AIUs since January 2, 2007.

Q. How have you developed the proposed price for the Reactive Demand Charge for those customers with a supply line voltage less than 100 kV?

A. The methodology is similar to that used for establishing the Transformation Capacity Charge. The incremental cost of installing new capacitor banks was examined, and have a simple average cost of about $0.30/kVAR for facilities installed at primary voltages and $0.63/kVAR for facilities installed at 34.5 kV and/or 69 kV. The cost range of facilities is $0.15/kVAR to $0.73/kVAR. The overall average percentage increase for all DS-4 customers combined for all of the Ameren Illinois Utilities (excluding the impact of the Distribution Tax) is approximately 21%. A 21% increase to the Reactive Demand Charge yields $0.29/kVAR, and is the price proposed by the AIUs. The proposed charge is near the incremental cost of capacitor banks, which gives customers an economic choice to allow AIUs to correct for potential voltage issues on the delivery system, or improve their power factor on the customer's side of the meter.

Q. Will assessing the Reactive Demand Charge influence the development of the Distribution Delivery Charge?

A. Yes. The Distribution Delivery Charge for DS-4 is lower than it otherwise would be in the absence of the Reactive Demand Charge.

4. DISTRIBUTION DELIVERY CHARGES

Q. Please discuss the general approach used to develop prices for the Distribution Delivery Charge for DS-3 and DS-4 in the Ameren Illinois Utilities' previous DS rate cases.

A. The Distribution Delivery Charge for customers with demands of 150 kW and over are currently demand based and voltage differentiated. Recovering demand related distribution costs from customers based on their demand better matches pricing to how cost are incurred. In general, customers served at lower voltages require additional investment in distribution facilities as compared to customers served at higher voltages. Thus, voltage differentiated pricing reflects the costs incurred to serve customers, and is higher for low voltage customers and lower for high voltage customers. The stated Distribution Delivery Charges will recover the cost of providing power up to the point of final transformation provided by the AIUs. Distribution Delivery Charges are also assessed based on a customer’s supply line voltage. In general, supply line voltage is the high side voltage of AIU supplied power before final transformation to the voltage used by the customer. Using supply line voltage is a benefit to customers served at higher voltage and who skip one or more levels of typical progression through the transformation system. For example, a large customer may take delivery at 12.47 kV but be supplied by a 138 kV line. In this case, the customer would pay the “over 100 kV” Distribution Delivery Charge and a Transformation Charge. The customer does not utilize the high voltage (typically 34.5 kV or 69 kV) facilities and, therefore, avoids paying for facilities not used.

Q. Please explain how proposed DS-3 and DS-4 Distribution Delivery Charges were developed.

A. Proposed Distribution Delivery Charges were developed using an approach similar to that used to establish prices for the same components in Dockets Nos. 06-0070 – 06-0072 (cons). The demand related costs for DS-3 and DS-4 were combined and divided by the combined voltage differentiated demands. Combining costs and demands by voltage recognizes that, conceptually, providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW. However, as discussed in Ameren Exhibit 16.1E (the Analysis of DS-3 & DS-4 Rate Classes), while the cost of providing a kW of service may be similar, the revenue contribution from customers is not if the kW used in billing is different from the kW unit used in a cost of service model. This is the case today.

The Distribution Delivery Charge is assessed based on the greater of a customer’s monthly maximum on-peak demand or 50% of its off-peak demand. Conversely, costs are allocated predominantly based on each class' non-coincident peak demand that occurs in the year. On average, the sum of DS-3 monthly billing demands relative to their non-coincident peak demand is lower than it is for DS-4. While DS-3 and DS-4 Distribution Delivery Charges share common starting points in their development, adjustments have been made to reflect that revenue contributions from DS-3 will be slightly less than those for DS-4 through the year. Ameren Exhibit 16.11E shows the development of Distribution Delivery Charges. Pages 1-3 show the common voltage differentiated unit demand costs prior to adjustments. Pages 4-6 show an adjustment to reflect the difference in monthly maximum demand to annual maximum demands. For the Primary voltage adjustment, the factors for each respective AIUs were used (as shown in the table in Ameren Exhibit 16.1E (the DS-3 & DS-4 analysis), page 5). For the High Voltage adjustment, the AIUs average value was used for each AIUs (see page 6 of Ameren Exhibit 16.1E) since there is relatively little load served at that voltage level for DS-3 and grouping DS-3's for all AIUs' smooth out anomalies that could occur due to a single customer.

Next, DS-4 demand prices were adjusted downward to reflect that the Reactive Demand Charge is an unbundled price component within DS-4. Revenue expected to be generated from the Reactive Demand Charge divided by total Distribution Delivery Charge revenue at present rates was used to develop a ratio used for the downward adjustment. This step is shown on pages 4-6, column 7-9 in Ameren Exhibit 16.11E.

Finally, the prices were adjusted by an equal percentage for each AIUs to achieve the target revenue allocation for DS-3 and DS-4, respectively. Adjusting the demand charges to recover the revenue for each individual DS class is necessary in order to arrive at the target revenue allocation amount for each class. This step is shown on pages 7-9 of Ameren Exhibit 16.11E. An unfortunate consequence to targeting each DS class' revenue allocation is that the gap between DS-3 and DS-4 proposed Distribution Delivery Charges widen compared to present rates. Relaxation of the revenue allocation constraint from the proposed 125% to about 200% would ensure that the existing dollar differential between DS-3 and DS-4 Distribution Delivery Charges would remain close to present levels. As discussed in the revenue allocation section above, the AIUs' believe a 125% constraint is appropriate at this time. Present and proposed voltage differentiated charges are shown in Ameren Exhibit 16.6E (price summary).

5. RATE LIMITER

Q. Please explain the provision for the Rate Limiter contained within DS-3 and DS-4.

A. Both DS-3 and DS-4 contain rate limiter provisions that ensure the monthly charges for the sum of Distribution Delivery and Transformation Charges are limited to no more than a set ¢/kWh value if 20% or less of the customer's annual usage occurs in the summer months of June through September. The limiter value is presently 2.613 ¢/kWh for AmerenIP, 2.223 ¢/kWh for AmerenCIPS, and 1.953 ¢/kWh for AmerenCILCO. The limiter values do not differ between DS-3 and DS-4. The rate limiter provision was implemented in conjunction with the ICC Final Order in the rate redesign case. At that same time, DS-3 and DS-4 Distribution Delivery Charges were increased to maintain revenue neutrality.

Q. Have you maintained the rate limiter provisions within proposed DS-3 and DS-4 tariffs?

A. The rate limiter provision has been retained, but limiter ¢/kWh amounts have been increased to a level so that the total dollar rate limitation effect is approximately the same under proposed rates as it is under present rates. The following table shows the present and proposed rate limiters, and the revenue effect of the rate limiters under present and proposed rates.

Summary of Present and Proposed Rate Limiters for DS-3 and DS-4

	Present		Proposed	
	¢/kWh	Dollars	¢/kWh	Dollars
AmerenIP	$0.02613	$(872,929)	$0.04000	$ (893,499)
AmerenCIPS	$0.02223	$(740,284)	$0.03000	$ (711,116)
AmerenCILCO	$0.01953	$(485,562)	$0.03000	$ (493,644)

If the rate limiter ¢/kWh values are not increased to reflect increases in the Distribution Delivery Charge and Transformation Capacity Charge, the rate limitation dollar amount will increase to $1,254,000 for AmerenIP, $976,876 for AmerenCIPS, and $681,636 for AmerenCILCO.

Q. Is there still a need for a rate limiter provision?

A. In the last rate case order, the Commission found the rate limiter provision had not been in place for a sufficient period of time. The Commission stated "The Commission is committed to eliminating these rate limiters at the earliest opportunity; however, the Commission concludes that the time to do so has not yet arrived." (Final Order Nos. 07-0585 et.al. (cons.), p 354). In the prior rate case, the AIUs recommended that the rate limiter change from 2 cents/kWh to 3 cents/kWh for DS-3 customers, and be eliminated for DS-4 customers. The AIUs position was based on the Final Order in Docket No. 07-0165 where the Commission stated the rate limiter should only be in place as long as necessary, recognizing that the provision was not cost based. Further, the AIUs proposed (and the Commission accepted) a change in how the monthly Billing

Demand was determined. The monthly Billing Demand was changed to be determined on the greater of the customer's monthly on-peak demand or 50% of the off-peak demand. This enhancement to the monthly Billing Demand allows rate limited customers to shift their use to the off-peak period to help manage costs, and became effective on October 1, 2008.

The AIUs proposal attempts to strike a balance between providing bill impact relief to seasonal customers and limiting the amount of subsidy placed on other customers to a dollar amount equal to that in rates today.

E. <u>LIGHTING SERVICE</u>

Q. What is the nature of service offered under the AIU's proposed lighting rates, Rate DS-5?

A. Proposed DS-5 provides customers with dusk-to-dawn, photo-cell controlled lighting service. The AIUs' will typically own and maintain the lighting fixture, but DS-5 also contains provisions for customers who own their own lighting facilities. The Fixture Charges in DS-5 do not include power and energy, transmission or delivery service charges, which are separately stated. Transmission and energy charges are charged separately through Rider TS and Rider BGS if customers choose to take power and energy service from AIUs, and distribution delivery charges are assessed through a separate component within DS-5.

Q. What types of lighting fixtures are offered by the AIU's?

A. In Docket Nos. 06-0070-0072 (cons.), the Commission accepted AIUs proposal to establish a set of uniform offerings for new fixtures. Fixtures offered prior to January 2, 2007 that are no longer available to new installations, such as various Incandescent and

Mercury Vapor fixtures, were allowed to continue operation until the fixture required maintenance. Such "grandfathered" fixtures are set to be replaced by a comparable Sodium Vapor fixture. Fixture prices for grandfathered lights are priced based on the replacement fixture. For example, the 175 watt Mercury Vapor fixture is set to be replaced by a 100 watt Sodium Vapor fixture, and thus both are assessed the same fixture price. The standard fixtures offered by the AIUs are as follows:

Area	Directional	Decorative
Sodium Vapor 100 W Sodium Vapor 250 W Sodium Vapor 400 W Metal Halide 250 W Metal Halide 400 W	Sodium Vapor 250 W Sodium Vapor 400 W Metal Halide 250 W Metal Halide 400 W	Sodium Vapor 100 W Metal Halide 175 W

Q. Are there any changes to the standard fixtures offered by the AIUs?

A. The decorative Metal Halide 175 watt fixture can no longer be purchased and is proposed to be replaced with a Metal Halide 150 watt fixture. The AIUs propose to place the existing Metal Halide 175 watt fixture within the "grandfathering" section of the tariff and note that such fixtures will be replaced with Metal Halide 150 watt fixtures in the future. The AIU's plan to file a tariff change to present DS-5 within a few weeks of this filing to restrict the availability of Metal Halide 175 watt fixtures.

Q. How were lighting rates established in the last rate case?

A. All lighting fixtures and lighting component prices were adjusted on an across-the-board basis. Any applicable Metering and Customer Charges were linked to those established for DS-2, Small General Service.

Q. Where objections raised regarding use of the across-the-board approach?

A. Yes. The Local Government Interveners ("LGI") objected to use of the across-the-board approach, and suggested an alternative. The Commission declined to implement the LGI's alternative in the last rate case, but did "require AIU to analyze the cost of lighting service in each of the utility's electric service areas and develop cost-based rates for lighting fixture charges, as proposed by LGI."

Q. Please summarize the LGI's proposal from the last rate case.

A. The LGI recommended that the next rate case filing include a detailed cost of service study showing a lighting cost of service analysis for identifying lighting fixture costs as well as a detailed street light rate design study to determine cost-based lighting fixture charges. The LGI also recommended in the last rate case that the fixture rates among the three AIUs move toward uniformity.

Q. Please describe the methodology used to arrive at proposed fixture prices.

A. The proposed pricing methodology is designed to move Fixture Charges for a comparable light for the three AIUs to a uniform level. The methodology involved three major steps. First, the incremental cost of each fixture type was determined, similar to the approach discussed in the last rate case, and the study provided in Docket Nos. 06-0070 – 06-0072 (cons.). A summary of the results of the incremental cost study for lighting fixtures is provided in Ameren Exhibit 16.12E. The next step determined the total fixture revenue that would be generated at incremental cost, and compared that revenue to the total cost of service allocated to DS-5 in the embedded cost of service study offered by Ms. Althoff. The overall ratio of DS-5 embedded costs to revenue at incremental costs was applied to each individual incremental fixture cost to arrive at a target uniform fixture price. The third step examined the fixture revenue generated at existing charges and compared that amount to fixture revenue that would be generated at target uniform fixture charges. The proposed Fixture Charges emerge from the third step and have been set so that the change to the 100 Watt Sodium Vapor Fixture Charge is approximately within a +/- $1/month bandwidth.

Results of the proposed lighting pricing methodology indicate that the Fixture Prices for AmerenIP should decrease by about 10%, increase for AmerenCIPS by about 29.8%, and decrease by about 5% for AmerenCILCO. The total revenue change to the DS-5 class is also influenced by other revenue items such as the Distribution Delivery Charge, miscellaneous rental fees, a grandfathered pole charge (AmerenIP only), and Customer and Meter Charges. After the effect of those other revenue items is included, the DS-5 class is proposed to receive an 8.3% decrease for AmerenIP, a 15.5% increase for AmerenCIPS, and a 0.7% decrease for AmerenCILCO.

See Ameren Exhibit 16.13E for the proposed DS-5 Fixture and other related charges.

VI. REVENUE EFFECT OF PROPOSED ELECTRIC TARIFFS (BILLING DETERMINANTS)

Q. Have you prepared a summary of the revenue generated by applying present and proposed prices to test-year billing units?

A. Yes. Ameren Exhibit 16.14E is a replica of Part 285 Schedule E-5, and shows the electric service detailed billing determinants and provides the revenues expected under present and proposed tariff charges. The revenue increase was computed by billing weather normalized billing determinants for the test year of the 12 months ending December 31, 2008 at present and proposed DS rates.

Q. What period of weather was used to normalize sales?

A. Weather for the period from 1999 through 2008 was used. Use of a ten year period is consistent with the period used for the each of the AIUs' gas cases. The weather normalization procedure is more fully described in Part 285 Schedule E-4(a)(2).

Q. Were other adjustments made to test year billing units?

A. Yes. In addition to weather normalization, sales were reduced to reflect continued growth in incremental energy efficiency programs. Additionally, adjustments were made to reflect customer load reductions in AmerenIP and AmerenCILCO service areas.

VII. ALTERNATIVES CONSIDERED

Q. Did you consider any alternatives when conducting your analysis?

A. Yes, as directed by the Commission in the order to the last rate cases, I also developed rates that recover class revenue equal to the cost of service results (Final Order, p. 281).

Q. Please provide your analysis with regard to cost based rates.

A. The analysis is provided in Ameren Exhibit 16.15E.

Q. What are your recommendations with regard to cost based rates?

A. As noted above, the AIUs have proposed to mitigate the rate changes to customer classes due to bill impact concerns, and thus decline to adopt the results from this study.

VIII. MISCELLANEOUS CHANGES TO EXISTING TARIFFS

Q. Please briefly describe the tariff changes the Ameren Illinois Utilities are proposing.

A. The proposed rate schedules are shown in Part 285 Schedule E-1, and changes to existing tariffs are shown in redline/strikeout format in Part 285 Schedule E-2. The tariff structure is substantially identical among the Ameren Illinois Utilities, except for individual DS tariff prices. Additionally, Ameren Illinois Utilities witnesses Robert Mill provides testimony on the introduction of a new rider for the Ameren Illinois Utilities' electric operations: and Rider VGP – Voluntary Green Program tariff.

Q. What change is proposed for Rate DS-2–Small General Delivery Service?

A. A slight modification to the Unmetered Service provision is proposed. The present tariff requires customers with continuous or regularly scheduled loads under 5 kW to request unmetered service. The proposed change will make unmetered service the preferred choice for such small, continuous or regularly scheduled loads.

Q. Please describe the changes to the Ameren Illinois Utilities' proposed Customer Terms and Conditions.

A. The changes to the Customer Terms and Conditions clarify the definition of "Demand" as that term is used through the electric service schedules. Presently, Demand and "Billing Demand" share the same definition within the Customer Terms and Conditions, but the term "Billing Demand" is adjusted within both DS-3 and DS-4 to carry a slightly different meaning. Billing Demand as used in DS-3 and DS-4 is the higher of the maximum Demand occurring On-Peak in the Billing Period or 50% of the highest Demand occurring in the Off-Peak in the Billing Period. The term Demand means the highest average load in kW during any fifteen minute interval during the time between regular meter readings. The phrase "or Billing Demand" within the Customer Terms and Conditions tariff definition of Demand has been adjusted to exclude the "or

Billing Demand" term, and all references to "Billing Demand" outside of DS-3 or DS-4 have been changed to reference "Demand" instead.

Changes within DS-3 and DS-4, and Rider RDC – Reserve Distribution Capacity, were also made to clarify that Demand and billing demand are not interchangeable terms.

Q. Please describe the changes to the Ameren Illinois Utilities proposed Standards and Qualifications for Electric Service.

A. There is one proposed change to the Standards and Qualifications for Electric Service. The section pertaining to Meter Reading has been amended to include a provision to require customers to provide a means for remote meter interrogation when AIUs personnel do not have free access to meters located within a customer substation or where additional training is required by customer in order to gain access to customer's property for meter access. If customer fails to provide access to an operating phone line, the AIUs may assess a $170 incremental fee per meter read.

Q. Please describe the change to Rider QF – Qualifying Facilities.

A. The proposed modification to Rider QF eliminates a provision where the AIUs could refuse to accept output from a qualifying facility when sale of output does not permit the AIUs to avoid costs. Presently the AIUs use QF purchases to offset power procured on behalf of fixed price customers. All other things constant, QF purchases reduce the need to purchase incremental power to serve fixed price customers. Such purchases usually influence the quantity of energy the AIUs buy and sell through the MISO administered markets as it balances its fixed price energy portfolio. As long as there is a MISO administered market, the AIUs do not anticipate a situation where sale of output from a customer's QF would permit the AIUs to avoid costs. As such, the AIUs propose to eliminate this section.

Q. Please describe the change to Rider PER.

A. The change to Rider PER is necessary if the Commission accepts the AIUs proposal to adjust BGS-1 and BGS-2 prices in this proceeding. Rider PER would point to this docket as establishing BGS base prices, replacing a reference to the rate redesign case, Docket Nos. 07-0165 (cons.).

IX. <u>SUPPLY COST ADJUSTMENTS</u>

Q. What are the components that make up the AIUs' Supply Cost Adjustment?

A. The AIUs Supply Cost Adjustment (SCA) are components that relate to the provision of AIUs supplied power and energy. The SCA contains three components: the Supply Procurement Adjustment, a Cash Working Capital Adjustment, and an Uncollectibles Adjustment. The Commission has directed the AIUs to update these costs and/or factors in delivery services rate case proceedings.

The Supply Procurement Adjustment is intended to compensate each of the AIUs for all direct and indirect costs of procuring and administering power and energy supply for all customers, other than amounts recovered in other charges to customers receiving power and energy service from the AIUs. These costs consist of expenses such as professional fees, costs of engineering, supervision, insurance, payments for injury and damage awards, taxes, licenses, and any other administrative and general expense not already included in the cost of power and energy service.

The purpose of the AIUs' Cash Working Capital Adjustment is the equitable recovery of the time value of expenses incurred to purchase power and energy for customers in a manner that recognizes the time lag between the incurrence of these expenses and the revenue stream or receipts from customers who pay for said power and energy.

The Uncollectibles Adjustment "factor" is a fixed percentage adder applicable to AIUs supplied power and energy, and transmission service, differentiated by AIUs and by customer class. This factor has been calculated for each DS/BGS rate class based on the relative relationship between total uncollectibles expenses to the total bundled revenue amounts by class for the test year in this case. Ameren witness Mr. Ronald Stafford provides additional detail regarding each of the Supply Cost Adjustment factors.

Q. What changes to the level of the SCA factors are you proposing?

A. Mr. Stafford has calculated $1,443,593 in Supply Procurement Adjustment costs. Dividing that cost by the approximate load expected to be served through AIUs procured power in the 12 months from June 2009, or 17,728,653 MWh, is 0.008 ¢/kWh, which has decreased from 0.011 ¢/kWh. The proposed Cash Working Capital Adjustment is 1.0157%, which has increased from 0.7986%. The following table shows the proposed uncollectibles factors by AIUs and by class.

Ameren Illinois Utilities
Proposed Uncollectibles Factors

	AmerenCILCO	AmerenCIPS	AmerenIP
DS/BGS-1	0.01731	0.01819	0.01901
DS/BGS-2	0.00255	0.00146	0.00175
DS/BGS-3	0.00118	0.00081	0.00125
DS/BGS-4	0.00006	0.00016	0.00072
DS/BGS-5	0.00000	0.00000	0.00002

Q. What uncollectible expenses would these factors generate for DS (base rates) and BGS (purchased power) service by class?

A. The amounts are as follows:

Uncollectible Dollars

	Base Rates Uncollectible	Purchased Power Uncollectible	Total Avg. Uncollectible
AmerenCILCO			
DS/BGS-1	$1,131,757	$2,394,732	$3,526,489
DS/BGS-2	$65,382	$138,344	$203,726
DS/BGS-3	$13,885	$29,379	$43,263
DS/BGS-4	$1,023	$2,165	$3,188
DS/BGS-5	$0	$0	$0
Total	$1,212,046	$2,564,620	$3,776,667
AmerenCIPS			
DS/BGS-1	$2,309,138	$4,852,161	$7,161,299
DS/BGS-2	$92,431	$194,224	$286,655
DS/BGS-3	$24,093	$50,627	$74,721
DS/BGS-4	$1,610	$3,383	$4,993
DS/BGS-5	$0	$0	$0
Total	$2,427,272	$5,100,395	$7,527,667
AmerenIP			
DS/BGS-1	$4,970,946	$6,862,289	$11,833,235
DS/BGS-2	$206,868	$285,577	$492,445
DS/BGS-3	$61,087	$84,330	$145,417
DS/BGS-4	$14,915	$20,589	$35,504
DS/BGS-5	$307	$424	$732
Total	$5,254,123	$7,253,210	$12,507,333

Q. Are you proposing to change the methodology used to develop a total SCA?

A. No. Customers taking service under the utility's fixed price option, Rider BGS, will have a constant SCA applied to each kWh of use, as they do today. Moreover, customers taking service under Rider RTP will likewise continue to pay the same constant SCA applied to each kWh of use as BGS customers pay. Customers taking service under the AIU's hourly priced service generally available to customers with demands over 400 kW, Rider HSS, will continue to have the three components applied to the hourly prices as they do today.

X. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX

STATEMENT OF QUALIFICATIONS
LEONARD M. JONES

My name is Leonard M. Jones. My business address is One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103. I am employed by Ameren Services Company as Managing Supervisor – Restructured Services – Regulatory Policy and Planning.

I graduated from Western Illinois University with a Bachelor of Arts Degree in Economics in 1987. In 1988, I received a Master of Arts Degree in Economics, also from Western Illinois University. From 1988 through 2004 I was employed by Illinois Power Company (”Illinois Power”) as a Rate Analyst, Senior Rate Analyst, Rate Specialist, Team Leader - Costing and Economic Services, and Director – Business Planning and Forecasting. Shortly after completion of Ameren Corporation's ("Ameren") acquisition of Illinois Power, I was assigned to my current position.

I previously testified before the Illinois Commerce Commission in Docket No. 91-0335, regarding Illinois Power's electric marginal cost of service study; Docket No. 93-0183, regarding Illinois Power's gas marginal cost of service study; Docket No. 98-0348, regarding Illinois Power's proposed Rider DA-RTP II; Docket No. 98-0680, regarding the investigation concerning certain tariff provisions under Section 16-108 of the Public Utilities Act and related issues; Docket No. 98-0769, regarding requirements governing the form and content of contract summaries for the 1999 Neutral Fact Finder; Docket Nos. 99-0120 & 99-0134 (Cons.) regarding approval of Illinois Power's Delivery Service Implementation Plan and Tariffs; Docket Nos. 00-0259/00-0395/00-0461 (Cons.) regarding proposed Rider MVI and revisions to Rider TC; Docket 01-0432 regarding electric Delivery Service Tariff rate design and related matters; Docket 04-0476 regarding gas rate design; Docket Nos. 06-0070/06-0071/06-0072 (Cons.) regarding electric Delivery Service Tariff rate design and related matters; Docket Nos. 06-0691/06-0692/06-0693 (Cons.) regarding residential real-time pricing tariffs; Docket 06-0800 regarding an investigation into changes to auction process and the Ameren Illinois Utilities' market value tariffs (Rider MV); Docket 07-0165 regarding an investigation into the Ameren Illinois Utilities' rate design, Docket 07-0527 regarding tariff changes resulting from passage of the IPA Act; Docket 07-0585 – 07-0590 (cons.) regarding electric rate design; Docket 07-0539 regarding electric energy efficiency programs; and Docket 08-0104 regarding gas energy efficiency programs.