

**ILLINOIS COMMERCE COMMISSION**

**DOCKET NO. 09-\_\_\_\_\_**

**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**

**June 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?**

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

30 **Q. Please summarize the conclusions of your direct testimony.**

31 As detailed below, I conclude

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

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

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

49    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

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

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

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

60 **II. RATE OBJECTIVES AND RATE CLASSES**

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

63 A. The principle pricing objective used to guide the development of tariffs focused  
64 on designing and considering rates that are cost based, but also taking into account bill

65 impacts to customers, while providing the AIUs with a reasonable opportunity to earn  
 66 their authorized rate of return. We also acknowledge the current rates were last set in  
 67 October 2008. When these rates go into effect, customers will have had only  
 68 approximately 1 ½ years experience with the rates. Thus, we are mindful of the  
 69 principles of rate continuity and stabilization. Further, tariffs should be understandable to  
 70 the extent practical and easily administered by AIU personnel.

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

77 **Q. What are the proposed classes in this case?**

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

<u>Service Class</u>	<u>Delivery Service</u>	<u>Availability</u>
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

79 These service classifications are synchronous with the AIUs’ power supply or BGS  
 80 tariffs.

81 **Q. Why is it important?**

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

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

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

100 **III. REVENUE ALLOCATION**

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

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

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

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

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

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

122 For DS-5 (Lighting Service), steps were taken to create more Fixture Charge price  
123 uniformity among the AIUs'. Rate changes for this class were deemed too great to  
124 implement full uniformity at this time, thus movement was constrained so that the change  
125 in rates results in a limit of about \$1/fixture change to the HPS 100 W fixture price for  
126 the respective AIUs. Additional details pertaining to pricing are discussed in the  
127 description of the DS-5 lighting rate design changes. The result of the DS-5 revenue

128 allocation methodology is revenue reductions of approximately \$1.97 million, \$1.62  
129 million, and \$60,000 reallocated to each respective AIUs' DS-1 through DS-4 classes.  
130 This step is shown on Ameren Exhibit 16.2E in columns 5 and 6. Page 1 shows the  
131 values for AmerenIP, page 2 shows the determination for AmerenCIPS, and page 3  
132 provides the calculation for AmerenCILCO. The overall revenue allocation methodology  
133 reallocates this excess revenue amount pro-rata based on each class' present revenue  
134 contribution. The reallocation results in less than a 1.3 percentage point shift in rate  
135 change responsibility overall and to any one class.

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

138 A. The distribution tax has been included as an expense in the previous total revenue  
139 requirement calculation. The cost study used to develop prices for rates effective January  
140 2, 2007 allocated the distribution tax expense based on utility plant assets rather than  
141 kWh. The annual distribution tax is assessed to the AIUs based on the quantity of retail  
142 electricity delivered in Illinois, making it clearly driven by kWh sales and not based on  
143 plant assets (discussed more in the next section). The DS-3 and DS-4 classes were  
144 allocated approximately 11% and 8% of total plant in those cases, respectively, yet were  
145 responsible for approximately 12% and 43% of total kWh sales, respectively. In  
146 comparison, the residential class was allocated approximately 56% of total plant in those  
147 cases, yet was responsible for approximately 30% of total kWh sales. Thus, in this  
148 proceeding, the DS-4 class is receiving a much greater share of the distribution tax  
149 expense responsibility, which is greatly influencing the cost of service results shown by  
150 Ms. Althoff. Removing the influence of the Distribution Tax in the revenue allocation

151 methodology ensures that each class pays its fair share of the expense. Moreover, for  
152 some large non-residential customers, the Distribution Tax will be as great as or larger  
153 than the entire delivery services amount due. For example, a DS-4 customer served from  
154 supply lines greater than 100 kV, 10 MW of peak demand and a 50% load factor would  
155 pay a delivery services bill of about \$3,432 at AmerenCILCO, \$3,662 at AmerenCIPS,  
156 and \$3,862 at AmerenIP under present rates while the Distribution Tax for that same  
157 customer would be about \$3,240 at AmerenCILCO, \$4,644 at AmerenCIPS, and \$4,968  
158 at AmerenIP. This represents a sharp percentage increase in delivery service costs, but  
159 viewed against a total bill including power costs, the Distribution Tax represents about  
160 2% to 3% of the total electric bill (assuming 4.5 ¢/kWh cost for power and energy  
161 supply).

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

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

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

172 A. In general, bill impact concerns are indeed a concern and this is in part why the  
173 AIUs have proposed to limit increases to any one class to no more than 125% of the  
174 average increase excluding the effect of the Distribution Tax. The total increases to DS-4  
175 would have approached 100% if not for the proposed revenue allocation limitation. That  
176 said, the percentage amounts should also be kept in perspective. In a previous answer, an  
177 example was provided showing that application of the Distribution Tax to a customer  
178 served from a +100 kV supply line voltage would experience a 100% increase, but only a  
179 2% to 3% overall increase to their total bill including power priced at 4.5 cents/kWh.  
180 As will be shown later, the Distribution Tax amounts are 0.138 ¢/kWh for AmerenIP,  
181 0.129 ¢/kWh for AmerenCIPS, and 0.090 ¢/kWh for AmerenCILCO.

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

184 A. The rates of the Ameren Illinois Utilities have undergone a significant transition  
185 from 2006 bundled rates to tariffs in effect today. In 2006, the Commission established  
186 cost based Delivery Services rates by following the results of an embedded cost of  
187 service study, and directed the AIU's to set rates to recover revenue sufficient to provide  
188 an equalized rate of return from each class. In 2007, both DS and BGS rates were  
189 modified in the "rate redesign docket" to address severe customer impacts. Those  
190 changes took effect in December 2007 (BGS) and January 2008 (DS). The most recent  
191 delivery service rate case applied an across-the-board change to rates, rather than a  
192 revenue allocation method that more closely utilized cost of service results, primarily out  
193 of concern for creating disproportionate bill impacts. Those changes were implemented  
194 on October 1, 2008. Assuming this proceeding is suspended for an 11 month period,

195 these rates will not go into effect until May 2010. Thus, approximately 2.5 years will  
196 have passed since the rate redesign case, and nearly 3.5 years since DS rates had been  
197 established in direct alignment with the results of a cost of service study. Applying a  
198 constrained revenue allocation resumes the practice of making steps toward cost-based  
199 rates, while helping to minimize the potential for disproportionate bill impacts to  
200 customers.

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

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

212 **IV. DISTRIBUTION TAX**

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

214 A. The Distribution Tax is described in the Public Utilities Revenue Act, 35 ILCS  
215 620. It is my understanding it replaced the "invested capital tax" when the Customer  
216 choice Act was passed in December 1997. The Distribution Tax is levied on electric

217 utilities based on the total amount of energy delivered in a year at differing rates for up to  
 218 seven different kWh sales blocks. The kWh sales blocks and effective rate for each of  
 219 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

220 Average Distribution Tax Rate 

\$ 0.00138	\$ 0.00129	\$ 0.00090
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221 **Q. Are the Ameren Illinois Utilities proposing a different way to account for and**  
 222 **recover the Distribution Tax?**

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

229 presentment purposes, yet accounted for and separately tracked within the AIUs' billing  
230 system.

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

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

240 **Q. How will the Distribution Tax tariff provisions operate?**

241 A. The Distribution Tax provides for an annual determination of an average rate for  
242 each AIUs based on forecast kWh information. Differences between the amount of  
243 Distribution Tax paid to the State and tax revenue collected will be included in the  
244 second subsequent year. Additionally, any refund amount received from the Illinois  
245 Department of Revenue for the previous tax period will be included in the calculation for  
246 the tax rate in the second subsequent year. For example, the tax revenue collected for  
247 year 2010 will be known in January 2011, and any tax refund amount for 2010 will be  
248 received by December 2011. All known tax costs and revenues will be incorporated  
249 within the development of the Distribution Tax rate for the year 2012. A copy of the

250 proposed Distribution Tax language within the Tax Additions tariff has been provided for  
251 reference as Ameren Exhibit 16.3E.

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

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

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

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

268 **V. RECOMMENDED RATE DESIGN**

269 **Q. Please describe the tariffs that constitute bundled rates.**

270 A. Rates for electric service may be differentiated into three categories that when  
271 added together, constitute fully bundled service. The first set of rates pertains to the

272 delivery of electricity through wires or other assets owned by the AIUs and under the  
273 jurisdiction of the Commission. Delivery service costs will be recovered from customers  
274 under the proposed Delivery Service tariffs filed in this docket. The second set of rates  
275 pertains to transmission service provided by or procured by the AIUs on behalf of its  
276 customers, under the jurisdiction of the Federal Energy Regulatory Commission.  
277 Transmission service costs will continue to be recovered from customers under Rider TS.  
278 The third set of rates applies to the provision of electric energy. Customers may take  
279 power from the AIUs' through Riders BGS, RTP, or HSS, as applicable. Customers that  
280 elect to take electric energy needs from a third party supplier will not be subject to the  
281 power supply provisions of Riders BGS, RTP or HSS, or the transmission service  
282 provisions under Rider TS. These customers' transmission services will presumably be  
283 arranged by their suppliers.

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

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

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

292 A. In general, the Ameren Illinois Utilities seek to maintain the pricing structure  
293 previously approved. For DS-1, the AIUs propose to reinstate uniform Meter Charges

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

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

316 for AmerenCIPS DS-5 Fixture Charges. The proposed Fixture Charges for  
317 AmerenCILCO are set at the uniform price target level.

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

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

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

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

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

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

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

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

347 **A. METER CHARGES**

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

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

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

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

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

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

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

377 **B. RESIDENTIAL SERVICE**

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

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

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

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

393 A. Yes.

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

396 A. Yes. The Commission stated as follows:

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

405  
406 “An analysis of the effect of dynamic market-based prices for the all-electric sub-  
407 class of residential customers would give the Commission valuable insight as to  
408 its potential benefits as the utility tries to meet those important and some times  
409 mutually exclusive, objectives in the next rate case. In its cost of service analysis,  
410 AIUs’ electric utilities should develop a separate sub-class for the residential  
411 space-heat customers and consider the use of a straight-fixed-variable rate design  
412 for this sub-class of customers if a dynamic pricing rate design utilizing market-  
413 based rates can be shown to be beneficial.” (Final Order 07-0585 et. al. (cons.),  
414 p. 282)

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

417 A. Rider BGS prices available to residential customers (BGS-1, a component of  
418 Rider BGS – Basic Generation Service) were realigned to reinstate a special electric  
419 space-heat discounted power rate for customers that previously received a special  
420 discounted rate prior to January 2, 2007 for AmerenIP and AmerenCIPS. (January 2,  
421 2007 was the date fully bundled legacy rates expired and unbundled rates took effect.)  
422 For AmerenCILCO customers and AmerenCIPS customers served under rates formerly  
423 applicable to Union Electric Company’s Illinois customers (Metro-East customers), there  
424 was no special discounted rate available to only electric space-heat customers prior to  
425 January 2, 2007. Instead, the rate structures for those two service areas contained non-  
426 summer declining block rates applicable to all customers. Electric space-heat customers  
427 in those service areas received the benefit of discounted rates, but were not separately  
428 identified for billing purposes. Similarly, the rate redesign case provided discounted  
429 BGS-1 prices for non-summer use over 800 kWh for all customers in those service  
430 territories. Doing so leveled the bill impacts experienced by customers, and dramatically  
431 lowered impacts to customers that heat their homes using electricity.

432 Creating discounted non-summer tail block rates for AmerenIP (space-heat only),  
433 AmerenCIPS (space-heat only), AmerenCIPS Metro East (all customers), and  
434 AmerenCILCO (all customers) required adjustments to other BGS prices to compensate.  
435 One adjustment was that prices for the first 800 kWh of non-summer residential use was  
436 increased by about 1.0 ¢/kWh for AmerenCILCO and AmerenCIPS, and by about 0.37  
437 ¢/kWh for AmerenIP. These initial block prices are uniform for space-heat and non-

438 space heat customers alike, but differ slightly by AIUs. Prior to the rate redesign  
439 adjustment, the initial block charge for each AIUs was nearly uniform at about 7.6  
440 ¢/kWh.

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

443 A. No. The disparity in pricing can be seen when comparing the non-space heat  
444 (NSH) prices in the table below for AmerenCIPS and AmerenIP to the electric space heat  
445 prices. The marginal BGS-1 power prices for all residential customers using more than  
446 800 kWh are provided in the table below.

<b>BGS-1 Purchased Electricity Charges Effective June 1, 2009</b>						
	<u>CIPS-SH</u>	<u>CIPS-NSH</u>	<u>CIPS-ME</u>	<u>CILCO</u>	<u>IP-SH</u>	<u>IP-NSH</u>
Non-Summer						
Over 800	\$0.02367	\$0.05104	\$0.00992	\$0.02334	\$0.00885	\$0.04856

448 As shown, AmerenIP's space-heat customers, and all AmerenCIPS-ME customers  
449 experience a marginal rate of less than 1 ¢/kWh. The price for AmerenCIPS (Space  
450 Heat) and AmerenCILCO customers is more than twice that amount at about 2.4 ¢/kWh.  
451 By contrast, a customer taking service under Rider PSP/RTP would have paid about 5  
452 ¢/kWh for power in 2008, a value more in line with that for AmerenIP and AmerenCIPS  
453 NSH customers. Moreover, the weighted average price of non-summer power recently  
454 procured to serve BGS customers through the IPA was just under 5 ¢/kWh. Power  
455 market prices recently have been trading lower than they were in the first part of 2008,  
456 indicating that perhaps the hourly real-time price ("RTP") analysis represents a high-end  
457 estimate for non-summer prices for winter 2010. For example, on May 4, 2009 Platt's  
458 Power Forwards ("Platt's") reported the market for a block of Jan-Feb 2010 on-peak  
459 power at \$44.75/MWh and off-peak power at \$30.00/MWh. By contrast, on May 5,

460 2008, Platt's reported the market for a block of Jan-Feb 2010 on-peak power at  
461 \$80.50/MWh, and off-peak power was reported at \$48.75/MWh. Monthly RTP values  
462 for January – March 2008 averaged prices of around 6.0 ¢/kWh but by October –  
463 December began to dip to about 4.0 ¢/kWh. In all cases, the marginal cost of power is  
464 greater than the marginal BGS price generally available to customers that heat their  
465 homes using electricity.

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

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

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

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

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

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

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

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

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

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

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

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

527 As shown at the bottom of Ameren Exhibit 16.5E for each AIUs, the total variable  
528 price charged customers (BGS-1 plus DS-1 Delivery Charge) decrease for the first 800  
529 kWh of non-summer use, and increase by less than 0.5 ¢/kWh for non-summer use over  
530 800 kWh. In all cases, customers using more than 800 kWh in a non-summer period will  
531 experience a change in variable charges by no more than 10%. Present and proposed DS-  
532 1 and BGS-1 prices are summarized in Ameren Exhibit 16.6E.

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

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

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

543 A. Yes. The cost of service results indicate that as a group, residential space-heat  
544 customers provide a greater rate of return on allocated costs than non-space heat  
545 customers. The proposed rate design reduces the relative delivery service cost burden on

546 space-heat customers, while providing an offsetting benefit of lower BGS-1 costs to non-  
547 space heating customers.

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

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

555 Ameren Exhibit 16.8E, pages 1-2 provides a summary of several bill calculations  
556 at various usage amounts for each AIUs. For the "typical" non-space heat customer  
557 using 10,000 kWh, the net increase in the total bill is expected to be about 8.2%, 5.5%,  
558 6.0% and 5.8% or an average monthly amount of \$8.05, \$4.95, \$5.38 and \$5.36 for  
559 AmerenIP, AmerenCIPS, AmerenCIPS-ME and AmerenCILCO, respectively. A space-  
560 heat customer using 18,000 kWh per year could expect a net increase in the total bill of  
561 about 7.9%, 5.4%, 5.6% and 5.5% or an average monthly amount of \$10.61, \$6.92, \$6.72  
562 and \$7.38 for AmerenIP, AmerenCIPS, AmerenCIPS-ME and AmerenCILCO,  
563 respectively.

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

566 A. Yes. The proposed rate design attempts to balance the desire to reduce intra-class  
567 subsidies between space-heat and non-space heat customers, while ensuring that bill

568 impacts are within a manageable dollar or percentage amount. A reduction in the  
569 proposed Fixed Monthly Charge should be accompanied with an increase in the proposed  
570 non-summer tail block Distribution Delivery Charge. If the proposed non-summer tail  
571 block Distribution Delivery Charge is indeed raised, non-summer tail block BGS-1  
572 charges would also remain closer to existing below-market levels (unless the constraint of  
573 limiting the change to total tail block non-summer variable charges to 10% is relaxed).  
574 Decreasing the Fixed Monthly Charge without a corresponding increase to the  
575 Distribution Delivery Charge places upward pressure on prices required for the summer  
576 and initial block non-summer Distribution Delivery Charges. (Summer and initial block  
577 non-summer Distribution Delivery Charges would need to be increased in order to  
578 achieve the targeted DS-1 revenue requirement.)

579         Conversely, an increase to the proposed Fixed Monthly Charge may be  
580 accompanied with a decrease to the non-summer tail block Distribution Delivery Charge,  
581 although such move is not imperative. An increase to the proposed Fixed Monthly  
582 Charge from the level recommended by the AIUs, while not adjusting the proposed non-  
583 summer Distribution Delivery Charge further downward, would reduce the summer and  
584 non-summer initial block variable Distribution Delivery Charges by an amount required  
585 to offset the additional revenue generated from the greater Fixed Monthly Charge. If  
586 instead the tail block non-summer Distribution Delivery Charge is further reduced, the  
587 BGS-1 non-summer tail block rate should be increased by an offsetting amount in  
588 accordance with the proposed rate design model. In summary, the proposed rate designs  
589 involve trade-offs between fixed and variable rate components, and between variable DS

590 prices and BGS prices, all of which must be addressed in a coordinated fashion if the  
591 Commission modifies the proposed rate design.

592 C. **SMALL GENERAL SERVICE**

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

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

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

605 A. Yes.

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

608 A. Rider BGS prices available to small general service customers (BGS-2, a  
609 component of Rider BGS – Basic Generation Service) were realigned to lower bill  
610 impacts to larger non-summer use customers. Prior to rate redesign, BGS-2 prices were  
611 seasonally differentiated, but did not contain a usage block. That is, BGS-2 summer and

612 non-summer rates were the same for all usage within the respective season. The rate  
 613 redesign case added a non-summer usage block for the first 2,000 kWh and all use over  
 614 2,000 kWh for each AIUs. For AmerenCIPS, a summer usage block at the same level  
 615 was also added. The rate redesign adjustments are shown in the table below:

<b>Rate Redesign Adjustments for BGS-2</b>			
Summer (All Voltages)	<b>AmerenCIPS</b>	<b>AmerenCILCO</b>	<b>AmerenIP</b>
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)

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

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

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

631 10%) for AmerenIP and 0.60 ¢/kWh (or 10%) for AmerenCIPS over present variable  
632 rates with the goal of achieving flat non-summer BGS-2 prices. As shown on pages 2, 4,  
633 and 6 of Ameren Exhibit 16.9E, the gap between the initial and tail block BGS-2 rates  
634 has been reduced significantly for AmerenIP and AmerenCIPS, and eliminated the need  
635 for a blocked BGS-2 non-summer rate for AmerenCILCO. (The total variable charge  
636 increase for AmerenCILCO DS/BGS-2 customers for use over 2,000 kWh is 4.5%.)  
637 None of the rate changes result in a total summer or non-summer variable rate increase to  
638 DS/BGS-2 customers of more than 10.4%.

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

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

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

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

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

655

Percent Change Secondary Delivery Voltage	<u>AmerenIP</u>	<u>AmerenCIPS</u>	<u>AmerenCILCO</u>
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%

656

Proposed Rates Primary Delivery Voltage	<u>AmerenIP</u>	<u>AmerenCIPS</u>	<u>AmerenCILCO</u>
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

657

Proposed Rates High Voltage Delivery Voltage	<u>AmerenIP</u>	<u>AmerenCIPS</u>	<u>AmerenCILCO</u>
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

658

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

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

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

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

675 **D. GENERAL SERVICE AND LARGE GENERAL SERVICE**

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

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

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

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

688

**1. METER AND CUSTOMER CHARGES**

689

**Q. Earlier you mentioned that proposed Meter Charges are identical to existing**

690

**Meter Charges for DS-3 and DS-4. Are you proposing any changes to Customer**

691

**Charges for DS-3 and DS-4 customers?**

692

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

693

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

694

A. Similar to Meter Charges, the cost of service for customer components indicates

695

that the Customer Charge could be decreased. However, a decrease to the Customer

696

Charges would require other charges to increase by an even greater amount. Specifically,

697

the Distribution Delivery Charges would need to increase from those proposed. Under

698

the revenue allocation constraint proposed by the AIUs, a reduction to the Customer

699

Charges would result in a greater increase to DS-3 Distribution Delivery Charges relative

700

to those for DS-4, further widening the gap in that charge for those two classes. As

701

discussed in Ameren Exhibit 16.1E, closing the gap between DS-3 and DS-4 Distribution

702

Delivery Charges is preferential, subject to bill impact concerns. Maintaining existing

703

Customer (and Meter) Charges does not trigger bill impacts, and does not widen the gap

704

in Distribution Delivery Charges between DS-3 and DS-4, thus is recommended for this

705

proceeding.

706

**2. TRANSFORMATION CHARGE**

707

**Q. Why do the Ameren Illinois Utilities have a separately stated Transformation**

708

**Charge for DS-3 and DS-4?**

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

715 **Q. How has the proposed Transformation Charge been developed?**

716 A. The Transformation Charge is presently \$0.57/kW of a customer's maximum  
717 demand occurring in the most recent 12 monthly billing periods. The charge is identical  
718 for DS-3 and DS-4 customers for each of the AIUs. As with the Meter and Customer  
719 Charges, the AIUs propose to keep a uniform Transformation Charge. The level of the  
720 Transformation Charge is set by examining the replacement cost new (or incremental  
721 cost) of various transformation facilities. The incremental cost of transformation  
722 equipment is about \$0.75/kW (ranging from \$0.58/kW up to \$1.07/kW) and about  
723 \$1.44/kW for substations (ranging from \$1.09/kW up to \$1.90/kW). The AIU's propose  
724 a charge of \$0.65/kW, or an increase of about 14%. Proposing a greater increase to the  
725 Transformation Charge places upward pressure on the revenue credit associated with the  
726 Rate Limiter, which is discussed later. Absent the Rate Limiter provision, an increase to  
727 the Transformation Charge in line with the DS-3 and DS-4 class average of around 20%  
728 may be warranted.

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

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

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

746 **3. REACTIVE DEMAND CHARGE (DS-4 Only)**

747 **Q. What is reactive demand or power?**

748 A. Reactive power, measured in kVAR, is sometimes referred to as "wasted power".  
749 When combined with "real" power, or kW, one can determine how much total power is  
750 supplied. Total supplied power is measured in kVA. Distribution planners must design  
751 delivery systems to meet a customer's expected peak kVA demand. The typical industry  
752 billing unit is the kW. Use of only the kW as the delivery service billing unit can cause a

753 mismatch between costs to serve and delivery charges for individual customers within the  
754 class. Customers with a kVA value larger than the kW value will register a kVAR.

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

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

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

770 A. The methodology is similar to that used for establishing the Transformation  
771 Capacity Charge. The incremental cost of installing new capacitor banks was examined,  
772 and have a simple average cost of about \$0.30/kVAR for facilities installed at primary  
773 voltages and \$0.63/kVAR for facilities installed at 34.5 kV and/or 69 kV. The cost range  
774 of facilities is \$0.15/kVAR to \$0.73/kVAR. The overall average percentage increase for  
775 all DS-4 customers combined for all of the Ameren Illinois Utilities (excluding the

776 impact of the Distribution Tax) is approximately 21%. A 21% increase to the Reactive  
777 Demand Charge yields \$0.29/kVAR, and is the price proposed by the AIUs. The  
778 proposed charge is near the incremental cost of capacitor banks, which gives customers  
779 an economic choice to allow AIUs to correct for potential voltage issues on the delivery  
780 system, or improve their power factor on the customer's side of the meter.

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

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

785 **4. DISTRIBUTION DELIVERY CHARGES**

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

789 A. The Distribution Delivery Charge for customers with demands of 150 kW and  
790 over are currently demand based and voltage differentiated. Recovering demand related  
791 distribution costs from customers based on their demand better matches pricing to how  
792 cost are incurred. In general, customers served at lower voltages require additional  
793 investment in distribution facilities as compared to customers served at higher voltages.  
794 Thus, voltage differentiated pricing reflects the costs incurred to serve customers, and is  
795 higher for low voltage customers and lower for high voltage customers. The stated  
796 Distribution Delivery Charges will recover the cost of providing power up to the point of  
797 final transformation provided by the AIUs. Distribution Delivery Charges are also

798 assessed based on a customer's supply line voltage. In general, supply line voltage is the  
799 high side voltage of AIU supplied power before final transformation to the voltage used  
800 by the customer. Using supply line voltage is a benefit to customers served at higher  
801 voltage and who skip one or more levels of typical progression through the  
802 transformation system. For example, a large customer may take delivery at 12.47 kV but  
803 be supplied by a 138 kV line. In this case, the customer would pay the "over 100 kV"  
804 Distribution Delivery Charge and a Transformation Charge. The customer does not  
805 utilize the high voltage (typically 34.5 kV or 69 kV) facilities and, therefore, avoids  
806 paying for facilities not used.

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

809 A. Proposed Distribution Delivery Charges were developed using an approach  
810 similar to that used to establish prices for the same components in Dockets Nos. 06-0070  
811 – 06-0072 (cons). The demand related costs for DS-3 and DS-4 were combined and  
812 divided by the combined voltage differentiated demands. Combining costs and demands  
813 by voltage recognizes that, conceptually, providing a kW of service to customers at a  
814 given voltage level costs the same whether the customer requires 150 kW or 2,000 kW.  
815 However, as discussed in Ameren Exhibit 16.1E (the Analysis of DS-3 & DS-4 Rate  
816 Classes), while the cost of providing a kW of service may be similar, the revenue  
817 contribution from customers is not if the kW used in billing is different from the kW unit  
818 used in a cost of service model. This is the case today.

819 The Distribution Delivery Charge is assessed based on the greater of a customer's  
820 monthly maximum on-peak demand or 50% of its off-peak demand. Conversely, costs

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

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

841 Finally, the prices were adjusted by an equal percentage for each AIUs to achieve  
842 the target revenue allocation for DS-3 and DS-4, respectively. Adjusting the demand  
843 charges to recover the revenue for each individual DS class is necessary in order to arrive

844 at the target revenue allocation amount for each class. This step is shown on pages 7-9 of  
845 Ameren Exhibit 16.11E. An unfortunate consequence to targeting each DS class'  
846 revenue allocation is that the gap between DS-3 and DS-4 proposed Distribution Delivery  
847 Charges widen compared to present rates. Relaxation of the revenue allocation constraint  
848 from the proposed 125% to about 200% would ensure that the existing dollar differential  
849 between DS-3 and DS-4 Distribution Delivery Charges would remain close to present  
850 levels. As discussed in the revenue allocation section above, the AIUs' believe a 125%  
851 constraint is appropriate at this time. Present and proposed voltage differentiated charges  
852 are shown in Ameren Exhibit 16.6E (price summary).

853 **5. RATE LIMITER**

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

856 A. Both DS-3 and DS-4 contain rate limiter provisions that ensure the monthly  
857 charges for the sum of Distribution Delivery and Transformation Charges are limited to  
858 no more than a set ¢/kWh value if 20% or less of the customer's annual usage occurs in  
859 the summer months of June through September. The limiter value is presently 2.613  
860 ¢/kWh for AmerenIP, 2.223 ¢/kWh for AmerenCIPS, and 1.953 ¢/kWh for  
861 AmerenCILCO. The limiter values do not differ between DS-3 and DS-4. The rate  
862 limiter provision was implemented in conjunction with the ICC Final Order in the rate  
863 redesign case. At that same time, DS-3 and DS-4 Distribution Delivery Charges were  
864 increased to maintain revenue neutrality.

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

867 A. The rate limiter provision has been retained, but limiter ¢/kWh amounts have  
 868 been increased to a level so that the total dollar rate limitation effect is approximately the  
 869 same under proposed rates as it is under present rates. The following table shows the  
 870 present and proposed rate limiters, and the revenue effect of the rate limiters under  
 871 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)
872 AmerenCILCO	\$0.01953	\$(485,562)	\$0.03000	\$(493,644)

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

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

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

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

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

896 **E. LIGHTING SERVICE**

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

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

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

908 A. In Docket Nos. 06-0070-0072 (cons.), the Commission accepted AIUs proposal to  
909 establish a set of uniform offerings for new fixtures. Fixtures offered prior to January 2,  
910 2007 that are no longer available to new installations, such as various Incandescent and

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

917

<u>Area</u>	<u>Directional</u>	<u>Decorative</u>
Sodium Vapor 100 W	Sodium Vapor 250 W	Sodium Vapor 100 W
Sodium Vapor 250 W	Sodium Vapor 400 W	Metal Halide 175 W
Sodium Vapor 400 W	Metal Halide 250 W	
Metal Halide 250 W	Metal Halide 400 W	
Metal Halide 400 W		

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

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

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

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

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

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

935 **Q. Please summarize the LGI’s proposal from the last rate case.**

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

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

942 A. The proposed pricing methodology is designed to move Fixture Charges for a  
943 comparable light for the three AIUs to a uniform level. The methodology involved three  
944 major steps. First, the incremental cost of each fixture type was determined, similar to  
945 the approach discussed in the last rate case, and the study provided in Docket Nos. 06-  
946 0070 – 06-0072 (cons.). A summary of the results of the incremental cost study for  
947 lighting fixtures is provided in Ameren Exhibit 16.12E. The next step determined the  
948 total fixture revenue that would be generated at incremental cost, and compared that  
949 revenue to the total cost of service allocated to DS-5 in the embedded cost of service  
950 study offered by Ms. Althoff. The overall ratio of DS-5 embedded costs to revenue at  
951 incremental costs was applied to each individual incremental fixture cost to arrive at a  
952 target uniform fixture price. The third step examined the fixture revenue generated at

953 existing charges and compared that amount to fixture revenue that would be generated at  
954 target uniform fixture charges. The proposed Fixture Charges emerge from the third step  
955 and have been set so that the change to the 100 Watt Sodium Vapor Fixture Charge is  
956 approximately within a +/- \$1/month bandwidth.

957 Results of the proposed lighting pricing methodology indicate that the Fixture  
958 Prices for AmerenIP should decrease by about 10%, increase for AmerenCIPS by about  
959 29.8%, and decrease by about 5% for AmerenCILCO. The total revenue change to the  
960 DS-5 class is also influenced by other revenue items such as the Distribution Delivery  
961 Charge, miscellaneous rental fees, a grandfathered pole charge (AmerenIP only), and  
962 Customer and Meter Charges. After the effect of those other revenue items is included,  
963 the DS-5 class is proposed to receive an 8.3% decrease for AmerenIP, a 15.5% increase  
964 for AmerenCIPS, and a 0.7% decrease for AmerenCILCO.

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

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

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

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

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

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

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

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

984 **VII. ALTERNATIVES CONSIDERED**

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

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

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

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

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

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

994 **VIII. MISCELLANEOUS CHANGES TO EXISTING TARIFFS**

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

997 A. The proposed rate schedules are shown in Part 285 Schedule E-1, and changes to  
998 existing tariffs are shown in redline/strikeout format in Part 285 Schedule E-2. The tariff  
999 structure is substantially identical among the Ameren Illinois Utilities, except for  
1000 individual DS tariff prices. Additionally, Ameren Illinois Utilities witnesses Robert Mill  
1001 provides testimony on the introduction of a new rider for the Ameren Illinois Utilities'  
1002 electric operations: and Rider VGP – Voluntary Green Program tariff.

1003 **Q. What change is proposed for Rate DS-2–Small General Delivery Service?**

1004 A. A slight modification to the Unmetered Service provision is proposed. The  
1005 present tariff requires customers with continuous or regularly scheduled loads under 5  
1006 kW to request unmetered service. The proposed change will make unmetered service the  
1007 preferred choice for such small, continuous or regularly scheduled loads.

1008 **Q. Please describe the changes to the Ameren Illinois Utilities' proposed**  
1009 **Customer Terms and Conditions.**

1010 A. The changes to the Customer Terms and Conditions clarify the definition of  
1011 “Demand” as that term is used through the electric service schedules. Presently, Demand  
1012 and “Billing Demand” share the same definition within the Customer Terms and  
1013 Conditions, but the term “Billing Demand” is adjusted within both DS-3 and DS-4 to  
1014 carry a slightly different meaning. Billing Demand as used in DS-3 and DS-4 is the  
1015 higher of the maximum Demand occurring On-Peak in the Billing Period or 50% of the  
1016 highest Demand occurring in the Off-Peak in the Billing Period. The term Demand  
1017 means the highest average load in kW during any fifteen minute interval during the time  
1018 between regular meter readings. The phrase “or Billing Demand” within the Customer  
1019 Terms and Conditions tariff definition of Demand has been adjusted to exclude the “or

1020 Billing Demand” term, and all references to “Billing Demand” outside of DS-3 or DS-4  
1021 have been changed to reference “Demand” instead.

1022 Changes within DS-3 and DS-4, and Rider RDC – Reserve Distribution Capacity,  
1023 were also made to clarify that Demand and billing demand are not interchangeable terms.

1024 **Q. Please describe the changes to the Ameren Illinois Utilities proposed**  
1025 **Standards and Qualifications for Electric Service.**

1026 A. There is one proposed change to the Standards and Qualifications for Electric  
1027 Service. The section pertaining to Meter Reading has been amended to include a  
1028 provision to require customers to provide a means for remote meter interrogation when  
1029 AIUs personnel do not have free access to meters located within a customer substation or  
1030 where additional training is required by customer in order to gain access to customer’s  
1031 property for meter access. If customer fails to provide access to an operating phone line,  
1032 the AIUs may assess a \$170 incremental fee per meter read.

1033 **Q. Please describe the change to Rider QF – Qualifying Facilities.**

1034 A. The proposed modification to Rider QF eliminates a provision where the AIUs  
1035 could refuse to accept output from a qualifying facility when sale of output does not  
1036 permit the AIUs to avoid costs. Presently the AIUs use QF purchases to offset power  
1037 procured on behalf of fixed price customers. All other things constant, QF purchases  
1038 reduce the need to purchase incremental power to serve fixed price customers. Such  
1039 purchases usually influence the quantity of energy the AIUs buy and sell through the  
1040 MISO administered markets as it balances its fixed price energy portfolio. As long as  
1041 there is a MISO administered market, the AIUs do not anticipate a situation where sale of

1042 output from a customer's QF would permit the AIUs to avoid costs. As such, the AIUs  
1043 propose to eliminate this section.

1044 **Q. Please describe the change to Rider PER.**

1045 A. The change to Rider PER is necessary if the Commission accepts the AIUs  
1046 proposal to adjust BGS-1 and BGS-2 prices in this proceeding. Rider PER would point  
1047 to this docket as establishing BGS base prices, replacing a reference to the rate redesign  
1048 case, Docket Nos. 07-0165 (cons.).

1049 **IX. SUPPLY COST ADJUSTMENTS**

1050 **Q. What are the components that make up the AIUs' Supply Cost Adjustment?**

1051 A. The AIUs Supply Cost Adjustment (SCA) are components that relate to the  
1052 provision of AIUs supplied power and energy. The SCA contains three components: the  
1053 Supply Procurement Adjustment, a Cash Working Capital Adjustment, and an  
1054 Uncollectibles Adjustment. The Commission has directed the AIUs to update these costs  
1055 and/or factors in delivery services rate case proceedings.

1056 The Supply Procurement Adjustment is intended to compensate each of the AIUs  
1057 for all direct and indirect costs of procuring and administering power and energy supply  
1058 for all customers, other than amounts recovered in other charges to customers receiving  
1059 power and energy service from the AIUs. These costs consist of expenses such as  
1060 professional fees, costs of engineering, supervision, insurance, payments for injury and  
1061 damage awards, taxes, licenses, and any other administrative and general expense not  
1062 already included in the cost of power and energy service.

1063 The purpose of the AIUs' Cash Working Capital Adjustment is the equitable  
1064 recovery of the time value of expenses incurred to purchase power and energy for  
1065 customers in a manner that recognizes the time lag between the incurrence of these  
1066 expenses and the revenue stream or receipts from customers who pay for said power and  
1067 energy.

1068 The Uncollectibles Adjustment "factor" is a fixed percentage adder applicable to  
1069 AIUs supplied power and energy, and transmission service, differentiated by AIUs and  
1070 by customer class. This factor has been calculated for each DS/BGS rate class based on  
1071 the relative relationship between total uncollectibles expenses to the total bundled  
1072 revenue amounts by class for the test year in this case. Ameren witness Mr. Ronald  
1073 Stafford provides additional detail regarding each of the Supply Cost Adjustment factors.

1074 **Q. What changes to the level of the SCA factors are you proposing?**

1075 A. Mr. Stafford has calculated \$1,443,593 in Supply Procurement Adjustment costs.  
1076 Dividing that cost by the approximate load expected to be served through AIUs procured  
1077 power in the 12 months from June 2009, or 17,728,653 MWh, is 0.008 ¢/kWh, which has  
1078 decreased from 0.011 ¢/kWh. The proposed Cash Working Capital Adjustment is  
1079 1.0157%, which has increased from 0.7986%. The following table shows the proposed  
1080 uncollectibles factors by AIUs and by class.

**Ameren Illinois Utilities  
Proposed Uncollectibles Factors**

	<u>AmerenCILCO</u>	<u>AmerenCIPS</u>	<u>AmerenIP</u>
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

1081 **Q. What uncollectible expenses would these factors generate for DS (base rates)**  
 1082 **and BGS (purchased power) service by class?**

1083 A. The amounts are as follows:

	<u>Uncollectible Dollars</u>		
	<u>Base Rates</u> <u>Uncollectible</u>	<u>Purchased Power</u> <u>Uncollectible</u>	<u>Total Avg.</u> <u>Uncollectible</u>
<b><u>AmerenCILCO</u></b>			
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
<b><u>AmerenCIPS</u></b>			
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
<b><u>AmerenIP</u></b>			
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

1084

1085 **Q. Are you proposing to change the methodology used to develop a total SCA?**

1086 A. No. Customers taking service under the utility's fixed price option, Rider BGS,  
 1087 will have a constant SCA applied to each kWh of use, as they do today. Moreover,  
 1088 customers taking service under Rider RTP will likewise continue to pay the same  
 1089 constant SCA applied to each kWh of use as BGS customers pay. Customers taking  
 1090 service under the AIU's hourly priced service generally available to customers with  
 1091 demands over 400 kW, Rider HSS, will continue to have the three components applied to  
 1092 the hourly prices as they do today.

1093 X. CONCLUSION

1094 Q. Does this conclude your direct testimony?

1095 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.