

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 07-0165

DIRECT TESTIMONY

OF

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Submitted On Behalf

Of

**CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO,
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS, and
ILLINOIS POWER COMPANY d/b/a AmerenIP**

(The Ameren Illinois Utilities)

May 11, 2007

24 A. Yes. I previously testified in Docket No. 91-0335, regarding Illinois Power's
25 electric marginal cost of service study; Docket No. 93-0183, regarding Illinois
26 Power's gas marginal cost of service study; Docket No. 98-0348, regarding
27 Illinois Power's proposed Rider DA-RTP II; Docket No. 98-0680, regarding the
28 investigation concerning certain tariff provisions under Section 16-108 of the
29 Public Utilities Act ("PUA" or "Act") and related issues; Docket No. 98-0769,
30 regarding requirements governing the form and content of contract summaries for
31 the 1999 Neutral Fact Finder; Docket Nos. 99-0120 & 99-0134 (Cons.) regarding
32 approval of Illinois Power's Delivery Service Implementation Plan and Tariffs;
33 Docket Nos. 00-0259/00-0395/00-0461 (Cons.) regarding proposed Rider MVI
34 and revisions to Rider TC; Docket No. 01-0432 regarding electric Delivery
35 Service Tariff rate design and related matters; Docket No. 04-0476 regarding gas
36 rate design; Docket Nos. 06-0070/06-0071/06-0072 (Cons.) regarding electric
37 Delivery Service Tariff rate design and related matters; Docket Nos. 06-0691/06-
38 0692/06-0693 (Cons.) regarding residential real-time pricing tariffs; and Docket
39 06-0800 regarding an investigation into changes to auction process and the
40 Ameren Illinois Utilities' market value tariffs (Rider MV).

41 **Q. What is the purpose of your direct testimony?**

42 A. In its Order Initiating Investigation in this proceeding, the Commission called for
43 an expedited review of the electric rate design for all customer classes of the
44 Ameren Illinois Utilities. Specifically, in finding (4), the Commission requires
45 that the investigation take into account all delivery services, all electric supply
46 services, and all other tariffed aspects of electric service, with a view toward

47 ordering changes in rate design that would take into account historic rate
48 structures. In this regard I have undertaken an analysis of the Ameren Illinois
49 Utilities' rate design of the Basic Generation Service and Delivery Service rates,
50 in the manner contemplated by the Commission's order.

51 **Q. Did the Commission's Order Initiating Investigation place any limits on the**
52 **scope of rate design changes?**

53 A. Yes. In finding (5) the Commission stated that it "does not intend to review or
54 consider any changes in the revenue requirement it has most recently determined
55 for the Ameren companies (or changes yet to be determined by the Commission
56 in the rehearing phase of Docket Nos. 06-0070, 06-0071, and 06-0072
57 (Consolidated)). Additionally, the Commission does not intend to modify its
58 conclusions (other than those related to rate design) in the Procurement Dockets".

59 **Q. Have the Ameren Illinois Utilities participated in workshops related to this**
60 **docket?**

61 A. Yes. The Ameren Illinois Utilities participated in four workshops related to this
62 docket, on April 11, April 18, April 25, and May 2, 2007. In each workshop, the
63 Ameren Illinois Utilities prepared documents and analyses to facilitate
64 discussions, attempted to identify types of customers that may be experiencing
65 above-average bill impacts, discussed various approaches to mitigate such
66 impacts, and provided an overview to the participating workshop parties of the
67 positive and negative sides of the various approaches.

68 Q. **Have the Ameren Illinois Utilities developed scenarios and other analytical**
 69 **work papers related to possible rate design alternatives to address the**
 70 **directives in the Commission's Order Initiating Investigation?**

71 A. Yes. On May 8, 2007, the Ameren Illinois Utilities submitted a supplemental
 72 informational filing containing a number of scenarios that address the directives
 73 contained in the Commission's Order Initiating Investigation. Those work papers
 74 were filed in this docket prior to the direct testimony due date in this case in order
 75 to allow all the parties to use those materials as a resource in preparing their direct
 76 testimony. My testimony incorporates the supplemental informational filing,
 77 which supports my direct testimony.

78 Q. **Please generally describe the schedules, graphs, and other documents**
 79 **provided as part of the Ameren Illinois Utilities' supplemental informational**
 80 **filing.**

81 A. The supplemental informational filing contained exhibits that were arranged in
 82 chronological order, according to when they were prepared. Together, they
 83 illustrate the analytical process leading up to the conclusions reached in this
 84 testimony. The exhibits contain the materials described in the table below:

85

Supplemental Information Exhibit No. 1 (Supp. Inf. Ex. 1)	Overview of pre-2007 bundled rates and illustrations relating thereto.
Supplemental Information Exhibit No. 2 (Supp. Inf. Ex. 2)	Explanation and illustrations concerning the difference between 2006 and 2007 rate structures.
Supplemental Information Exhibit No. 2.1 (Supp. Inf. Ex 2.1)	Residential Rate design scenarios. Four scenarios are explored for the purpose of evaluating the effectiveness of each in addressing the Commission's directives in this docket.

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Supplemental Information Exhibit No. 3 (Supp. Inf. Ex 3)	Overview of a multi-step process to redesign rates between residential and small non-residential customers.
Supplemental Information Exhibit No. 3.1 (Supp. Inf. Ex 3.1)	Provides a demonstration of Scenario A or the “all-electric” rate alternative. This alternative is also consistent with Staff’s mitigation approach.
Supplemental Information Exhibit No. 4 (Supp. Inf. Ex 4)	Revised multi-step approach.
Supplemental Information Exhibit No. 4.1 (Supp. Inf. Ex 4.1)	Comparison of alternative rate designs that employ both a block rate structure and a block rate together with a seasonal design element.

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Q. Please provide an overview of the existing rate design, specifically the Basic

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Generation Service (BGS) and Delivery Service (DS) designs.

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A. Customers may take power from the Ameren Illinois Utilities under BGS. BGS is

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provided to customers at a fixed price. BGS service is subdivided into classes of

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customers. In general, BGS is available to customers with demands under 1,000

93

kilowatts (“kW”). BGS-1 refers to service available to residential customers.

94

BGS-2 is provided to non-residential customers up to 150 kW of demand. BGS-3

95

is available to non-residential customers from 150 kW demand up to 1,000 kW

96

demand. BGS-5 is provided to lighting service customers or unmetered service

97

with a photo-cell control device. Collectively, BGS-1, 2, 3, and 5 are all procured

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under the same auction product (referred to as BGS-FP, where FP stands for

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Fixed Price). The BGS-FP auction product was bid for the entire Ameren-Illinois

100

footprint. Stated differently, the cost basis (winning auction value) is the same for

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each of the Ameren Illinois Utilities.

102

The winning BGS-FP auction value is price-shaped for each of the BGS

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categories (or classes) described above using a retail rate prism. The retail rate

Ameren Illinois Utilities' Exhibit 2.0

104 prism takes into consideration the usage patterns of each of the BGS classes to
105 develop average rates by season, or on- and off-peak. As a result, each BGS class
106 receives slightly different prices. BGS-1 contains a declining non-summer usage
107 block at 800 kWh, and is seasonally differentiated. BGS-2 is seasonally
108 differentiated, but does not contain a usage block. BGS-3 uses a time-of-use
109 structure where the prices vary by season and by on- and off-peak periods. BGS-
110 5 (lighting service on photo-cell controlled facility) reflects primarily off-peak
111 usage.

112 The rate class eligibility for BGS and DS employ the same criteria. For example,
113 DS-1 applies to residential customers, DS-2 applies to non-residential customers
114 with demands under 150 kW, etc. DS-1 contains a customer and meter charge, as
115 well as a Distribution Delivery Charge. The Distribution Delivery Charge is a flat
116 per kilowatt-hour (“kWh”) usage based charge. DS-2 also contains customer,
117 meter and a flat per/kWh Distribution Delivery Charge, similar to DS-1. DS-3
118 contains voltage differentiated customer, meter and demand based (\$/kW)
119 Distribution Delivery Charges. In addition, these customers also pay an
120 unbundled price for utility-provided transformation service. DS-5 charges
121 (lighting) contain a Fixture Charge that varies with the fixture type (e.g., 100 watt
122 sodium vapor, 400 watt sodium vapor, 175 watt metal halide, etc...). In addition,
123 these customers pay a kWh based Distribution Delivery Charge. DS-4 is
124 patterned after DS-3, except the tariff contains an additional provision for a
125 Reactive Demand Charge.

126 In addition to DS, if a customer takes power from one of the Ameren Illinois
127 Utilities, they must also pay for transmission service through Rider TS (the one
128 exception is for customers that take service under RTP-LI where application of
129 transmission service is directly applied, rather than through Rider TS).

130 **Q. What are some of the customer types experiencing above-average bill**
131 **impacts?**

132 A. In general, residential customers whose heating ventilation, and air conditioning
133 system relied solely on electricity for the heating of their homes experienced
134 increases much larger than the expected average increase. The average 2007 over
135 2006 increase for AmerenCILCO and AmerenCIPS customers residing in the
136 Metro-East region near St. Louis ("AmerenCIPS-ME") is about 55%. The
137 average increase for AmerenIP and AmerenCIPS customers residing outside the
138 Metro-East region near St. Louis ("AmerenCIPS") is about 40% and 37%,
139 respectively. By comparison, customers that heat their homes with electricity are
140 expected to experience increases greater than the class average. Page 3 of the
141 Order Initiating Investigation indicates increase percentages ranging from 88%
142 for AmerenCILCO to 170% for AmerenCIPS-ME. Actual impacts experienced
143 by residential customers were higher or lower depending on the customer's
144 monthly usage.

145 **Q. Please describe the impact on non-residential/small general service**
146 **customers.**

147 A. Non-residential/small general service customers are expected to experience
148 widely differing impacts. In general, customers with low usage (less than 2,000

149 kWh per month) are expected to experience below-average bill impacts, while
150 those above 2,000 kWh use are expected to experience average or above-average
151 bill impacts. Ameren Illinois Utilities' Exhibit 2.1, pages 21-27, illustrates the
152 distribution of non-residential rate increases, and the widely varying impacts. In
153 general, small-use customers received a relatively modest increase, or even a
154 decrease. As customer size increases within DS-2, impacts generally increase
155 into the above-average range.

156 **Q. Please discuss some possible solutions examined and depicted in the**
157 **informational filing, including the "Staff Mitigation Approach."**

158 A. Several scenarios are provided as part of the informational filing. Staff initially
159 proposed a mitigation approach in ICC Dockets No. 05-0160, 05-0161, and 05-
160 0162. Modifications to the mitigation approach were examined as well. The
161 mitigation approach employs a method where each class served by the BGS-FP
162 auction product – all customer classes under 1,000 kW of demand – would not
163 receive an average increase more than the greater of 20% or 150% of the average
164 increase for all BGS-FP customers. This calculation was performed by class for
165 each of the three Ameren Illinois Utilities.

166 The current application of the mitigation approach examines the average increases
167 for residential (DS/BGS-1), small non-residential (DS/BGS-2), general service
168 non-residential (DS/BGS-3), and lighting service (DS/BGS-5) classes. As shown
169 in Ameren Illinois Utilities Exhibit 2.1, page 37, no adjustment was warranted for
170 any class within AmerenIP and AmerenCILCO. For AmerenCIPS, the DS/BGS-3
171 class received a discounted rate of 0.267 cents/kWh, while the rates for all other

172 classes were raised by an amount to compensate for the revenue deficiency. The
173 mitigation adjustment applies to all kWh of BGS provided power.

174 **Q. How would the mitigation approach affect rates if the DS/BGS-1 class was**
175 **divided to include a subgroup for all electric customers?**

176 A. The results are shown in Ameren Illinois Utilities Exhibit 2.1, page 38. The
177 adjustment results in a rate decrease for AmerenCILCO DS/BGS-5 and a small
178 rate increase for all other groups. For AmerenIP, the all electric subclass would
179 receive a 1.162 cents/kWh credit and the rates for all other customer groups
180 would increase to compensate for the revenue deficiency. For AmerenCIPS, the
181 all electric subgroup would receive a 0.083 cents/kWh credit, the all electric
182 subgroup for AmerenCIPS-ME would receive a 1.051 cents/kWh credit, and the
183 DS/BGS-3 group would receive a credit of 0.225 cents/kWh. Rates for residential
184 general use, DS/BGS-2, and DS/BGS-5 would increase to compensate for the
185 revenue deficiency caused by the credits. While these results would help to
186 mitigate bill impacts, they would not produce material reductions in the bills of
187 residential all electric subgroup.

188 **Q. Would lowering the constraint from 150% to 125%, while including a**
189 **residential all electric residential subgroup, improve the result?**

190 A. Changing the mitigation constraint criteria to 125% does not provide a uniform
191 “fix” to bill impact issues among the utilities. The results are shown in Ameren
192 Illinois Utilities Exhibit 2.1, page 39. As shown, the subsidy provided to the
193 AmerenCIPS DS/BGS-3 group – a group that has already switched more than 1/3
194 of its load to third-party suppliers – increases to 0.744 cents/kWh. Shifting

195 additional dollars for recovery there would likely slow the pace of customer
196 switching, and may encourage those customers to return to BGS service to take
197 advantage of the subsidy. Conversely, the DS/BGS-3 rates for AmerenIP and
198 AmerenCILCO customers would be increased to subsidize other groups. This
199 rate increase would likely serve to accelerate switching.

200 **Q. Why is the issue of customer switching important to keep in mind?**

201 A. Rider MV contains a “true-up” mechanism that ensures costs and revenues match
202 over time for the entire customer base served by the BGS-FP product. As
203 previously stated, the BGS-FP product serves customers taking service under
204 BGS-1, -2, -3, and -5. All of these customers are also allowed to switch from
205 BGS-FP supply to supply with a third-party supplier. If additional cost recovery
206 were targeted to be recovered from BGS-3, these customers would be encouraged
207 to switch to a third-party supplier due to the higher BGS-3 price. Costs targeted
208 for recovery from BGS-3 would not be entirely recovered from BGS-3 customers.
209 Instead, recovery of costs will fall back to customers that remain on the Ameren
210 Illinois Utility-supplied product – primarily BGS-1 (residential) and BGS-2
211 (small non-residential) customers, and to a lesser extent BGS-3 customers, due to
212 the operation of the Rider MV over/under recovery mechanism. Therefore, it is
213 reasonable to conclude that it is best not to adjust BGS-3 rates at this point.

214 **Q. Does the outcome of the mitigation approach improve if the constraint is**
215 **adjusted to 100% instead of 150%, and the residential all electric subgroup is**
216 **created?**

217 A. Changing the mitigation approach to a 100% constraint did not result in an
218 improved solution. The DS/BGS-3 subsidy and subsidization issues were
219 exacerbated, and relief to all electric households may not be sufficient to address
220 bill impacts for each of the Ameren Illinois Utilities. For example, the mitigation
221 approach under this scenario would decrease rates for AmerenCIPS-ME all
222 electric residential customers by 2.109 cents/kWh. This credit would apply to all
223 kWh of use through the year. (Please see Ameren Illinois Utilities Exhibit 2.1,
224 page 40.) However, an rate comparison of 2006 bills to current 2007 expected
225 bills for AmerenCIPS-ME indicates that non-summer rates are expected to
226 increase by 100% or more, while summer rates are only about 5% higher than
227 2006. Applying the credit uniformly to summer and non-summer use seems to
228 provide a credit at times where one is not necessary to provide desired bill impact
229 relief.

230 **Q. Do you have a recommendation on how to use the results of these mitigation**
231 **approach studies?**

232 A. The results of the modified mitigation approach analyses are instructive and may
233 be used as a means to guide further analysis. For example, in each modified
234 analysis, the DS/BGS-2 class was targeted to subsidize other classes. This
235 suggests that the transition to current 2007 rates may not be as severe for these
236 customers. Moreover, the “all electric” residential subclass for each of the
237 Ameren Illinois Utilities was to receive a subsidy in the 125% and 150%
238 constraint scenarios. These observations were considered as we developed a more
239 focused methodology to provide relief to larger non-summer use customers.

240 **Q. Before you continue, do you have any general comments about the bill**
241 **impact scenarios contained in your testimony and in the informational**
242 **filings?**

243 A. Yes, I would note with all of the approaches that have been examined, the primary
244 focus is on mitigating certain customer impacts associated with the January 2,
245 2007 rates and rate design, not cost causation. Rate designs traditionally try to
246 move costs in a direction that links cost causation to the class of customers for
247 which cost recovery is expected. Rate change impacts are also an important
248 consideration; however, care should be taken in this docket to not focus entirely
249 on rate impacts, while ignoring the cost causation principles of proper rate design.
250 In the long-term, associating rates with cost causation should continue to be the
251 appropriate ratemaking goal of the Commission.

252 **Preferred Approach to Addressing Bill Impact Concerns**

253 **Q. Do the Ameren Illinois Utilities have a preferred approach to address bill**
254 **impact concerns associated with residential customers?**

255 A. Yes. The preferred rate redesign approach follows three primary steps. The first
256 step involves determining an average revenue target, and resulting percentage
257 increase, over bundled rates customers paid in 2006. This step allows for
258 subsidies from BGS-2 to BGS-1 if desired. Ameren Exhibit 2.2 illustrates
259 estimated revenue under 2006 rates for DS/BGS-1 and DS/BGS-2 customer
260 classes, and the total amount of revenue shift required to provide an equalized
261 percentage increase between the two classes. For each of the Ameren Illinois
262 Utilities, the percentage increase to the residential class is larger than the

263 percentage increase to the small general service class. Thus, equalizing increases
264 would result in a shift from DS/BGS-1 to DS/BGS-2. As shown, full equalization
265 would result in a \$30.9 million being shifted from BGS-1 to BGS-2 (or a 14.5 %
266 increase to DS/BGS-2) for AmerenIP, \$12.6 million (or 8.4 % increase to
267 DS/BGS-2) for AmerenCIPS, and \$10.9 million (or 17.5 % increase to DS/BGS-
268 2) for AmerenCILCO. The Ameren Illinois Utilities stop short of full
269 equalization for each of the Utilities. Instead of moving to full equalization, the
270 Ameren Illinois Utilities recommend limiting the percentage point increase shift
271 to 10%.

272 **Q. Why should the percentage point shift be limited to 10%?**

273 A. The Ameren Illinois Utilities are attempting to achieve an equitable balance
274 between residential and small general service classes. On one hand, the class
275 average increases suggest that the DS/BGS-2 class could absorb additional
276 revenue responsibility to equalize revenue between the residential and small
277 general service classes. On the other hand, movement of too much revenue to the
278 small general service customers may have the unintended consequence of creating
279 or adding to bill impact problems for these customers.

280 **Q. What are the subsidy amounts under a 10% limit?**

281 A. For AmerenIP, the limit would result in \$21.3 million of cost responsibility
282 moved from BGS-1 to BGS-2. For AmerenCILCO, the same limit results in a
283 \$6.2 million movement from BGS-1 to BGS-2. AmerenCIPS at 8.4% is already
284 under the 10% threshold and thus does not require further adjustment.

285 **Q. What is the second step of the residential rate redesign approach?**

286 A. The second step involves shifting DS revenues between the summer and non-
287 summer periods. Each of the Ameren Illinois Utilities experiences its annual peak
288 demand during the summer season. Some facilities are tied to an individual
289 customer's peak demand (e.g., service line, transformer). Other facilities are tied
290 to the collective peak demands of many customers connected to the same facilities
291 (e.g., high voltage 34.5 kV line, distribution substations). Conceptually, summer
292 demands drive a larger sizing of distribution facilities shared by many customers
293 than do non-summer demands. The size of the facilities often corresponds to the
294 cost of facilities.

295 Thus, the Ameren Illinois Utilities suggest that the Distribution Delivery Charge
296 for residential customers be increased by 0.75 cents/kWh in the summer, and
297 decreased by about 0.4 cents/kWh in the non-summer months. This movement is
298 supported in part with the conceptual cost rationale discussed above, and in part
299 by an outcome that will help lower bills for high non-summer use customers
300 during non-summer months. The design is revenue neutral within the DS-1 class
301 for each utility. In other words, annual DS-1 revenue is expected to be the same
302 for AmerenIP, AmerenCIPS, and AmerenCILCO. This step does not involve
303 BGS rates in any way. The particulars of this calculation are shown in Ameren
304 Exhibit 2.3 (see the bottom portion of the exhibit).

305 **Q. What is the third step of the residential rate design proposal?**

306 A. The third step of the residential rate design involves adjusting BGS rates to lessen
307 bill impacts for customers with higher non-summer kWh usage. This step
308 contains three sub-steps. First, the "all-in" rate for customers using more than

Ameren Illinois Utilities' Exhibit 2.0

309 800 kWh per month was set to a level that is no higher than the energy rate paid in
 310 2006 plus an amount equal to the average residential increase for the particular
 311 Utility. For example, rates in 2006 for AmerenCIPS-ME contained a tail block
 312 rate of 2.175 cents/kWh. The overall rate increase for all of AmerenCIPS is
 313 35.3%. Increasing the 2006 tail block rate of 2.175 cents/kWh by 35.3% results
 314 in a tail block target for AmerenCIPS-ME of 2.944 cents/kWh. This step requires
 315 that a separate category be continued for AmerenCIPS and AmerenIP customers
 316 that formerly took service under those Utilities' special "space-heat" rates. (Any
 317 premises that previously took service under the special electric heat rate would be
 318 assigned to the all-electric category for 2007 adjusted rates.) The following table
 319 illustrates tail block rates in 2006, the target class average increase, and the
 320 resulting tail block price targets for each Utility and subgroup.

	<u>CILCO</u>	<u>CIPS-NSH</u>	<u>CIPS-SH</u>	<u>CIPS-ME</u>	<u>IP-NSH</u>	<u>IP-SH</u>
<u>Winter Prices</u>						
2006 Marginal Price	\$ 0.03521	\$ 0.06988	\$ 0.03350	\$ 0.02175	\$ 0.05947	\$ 0.02499
Class 1&2 Avg Inc	152.4%	135.3%	135.3%	135.3%	135.3%	135.3%
Target Tail Block Rate	\$ 0.05365	\$ 0.09458	\$ 0.04534	\$ 0.02944	\$ 0.08047	\$ 0.03382

Note: The utility refers to the respective Ameren Illinois Utility. NSH refers to "non space-heat" or general use, and SH refers to "space-heat" or all electric.

321
 322 AmerenCILCO and AmerenCIPS-ME did not have tariffs in 2006 that required
 323 customers to qualify for a special "all electric" rate. Instead, all customers were
 324 billed under the same rates. Also note that for the AmerenCIPS all electric
 325 customer, the 9.458 cents/kWh target value is higher than rates under the 2007
 326 status quo. The non-summer tail block rates were not increased. In other words,
 327 the AmerenCIPS all electric tail block BGS rate was not adjusted from the 2007
 328 status quo.

329 Second, the summer rate was adjusted to a level 5% greater than the estimated
330 rate that customers are expected to pay in 2007.

331 Third, the prices for non-summer use for the first 800 kWh were increased to a
332 level to recover the balance of the overall target revenue level for each Utility.

333 The calculations are shown in Ameren Exhibit 2.3. As shown, the revenue target
334 for BGS-1 was an under-recovery of \$6.2 million for AmerenCILCO, \$21.3
335 million for AmerenIP, and \$12.6 million for AmerenCIPS. These costs will shift
336 to be recovered within BGS-2, which I will discuss shortly.

337 **Q. Are you concerned that the proposed target prices for non-summer use over**
338 **800 kWh per month vary widely among the Ameren Illinois Utilities and**
339 **between the general use and all electric groups?**

340 A. The Ameren Illinois Utilities view developing prices equal to costs as a rate
341 design objective. However, setting component prices to equal costs can
342 sometimes cause undue customer bill impacts. The evidence in this case indicates
343 that customers with high non-summer use, especially those who heated their
344 homes with electricity, have experienced significant bill impacts. This
345 methodology effectively addresses bill impacts, and eases the transition to fully
346 cost based rates at some future date.

347 **Q. Why was a 5% limit to summer rates chosen?**

348 A. The Ameren Illinois Utilities are once again attempting to achieve balance
349 between providing rate relief to those impacted the most (high non-summer use
350 customers), while not substantially impacting other customers. Approximately
351 15% of the Ameren Illinois Utilities' customers heat their households with

352 electricity. Stated another way, approximately 85% of customers are general use
353 customers where summer use is a more prominent component of total
354 consumption. Ameren Illinois Utilities' Exhibit 2.1, pages 4-7 and 12-15, show
355 that customers are expected to experience below-average increases to summer
356 bills (comparing 2006 rates to 2007 rates under the status quo). This suggests that
357 summer rates may be increased to help lower bills for high non-summer use
358 customers; however, applying a higher increase to 85% of the residential
359 customer base may cause unintended bill impact concerns for those customers.

360 **Q. Would summer rate changes become effective in 2007?**

361 A. No. The Commission's Order is not scheduled to be issued in this case until mid-
362 September. Consequently, the summer 2007 will have already passed before any
363 rate redesign changes are implemented. It will be summer 2008 before the
364 incremental 5% increase takes place.

365 **Q. What price adjustments would apply to AmerenCIPS customers that were**
366 **previously served under rates applicable to portions of Henderson and**
367 **Hancock counties in 2006?**

368 A. These customers would receive the same pricing as AmerenCIPS-ME customers.
369 The 2006 rate structure of "Henderson and Hancock" AmerenCIPS customers
370 was similar to that of AmerenCIPS-ME. The 2006 base prices were about 0.6
371 cents/kWh higher than those for AmerenCIPS-ME.

372 **Q. What is the result of applying the rate design changes on customer bills?**

373 A. Ameren Exhibit 2.4 provides a series of charts of bill comparisons at various
374 usage profiles. The first chart illustrates annual impacts for the various usages,

375 while the second and third charts on a page show summer and non-summer (non-
376 summer) impacts, respectively. The dotted line depicts the percentage increase
377 expected by comparing bill amounts at 2006 rates to bill amounts at expected
378 2007 rates under the status quo. The solid line represents the percentage increase
379 by comparing the same 2006 bill amount to bills at expected 2007 rates adjusted
380 as discussed above. As expected, adjusted 2007 summer rates are about 5%
381 higher than 2007 rates under the status quo. Also, adjusted 2007 non-summer
382 rates for all electric households are less than 2007 expected rates under the status
383 quo. In general, the impact to general use customers is modest. Annual increases
384 generally fall within 7% or less compared to 2007 rates under the status quo.
385 Annual bills for AmerenCIPS, AmerenCIPS-ME, AmerenCILCO, and AmerenIP
386 general use customers are expected to increase by about 7%, 5%, 5%, and 2%,
387 respectively. Further, average annual increase percentages for high non-summer
388 use customers move closer to the overall DS/BGS-1 class average.

389 **Q. How were rates for small non-residential customers (DS and BGS-2)**
390 **adjusted?**

391 A. The first step is shared by DS/BGS-2 and DS/BGS-1. As discussed with the
392 description of the residential methodology, BGS-2 is targeted to pick up an
393 additional by \$6.2 million for AmerenCILCO, \$21.3 million for AmerenIP, and
394 \$12.6 million for AmerenCIPS. The second step is very similar to that used by
395 the residential class. The Distribution Delivery Charge has been increased in the
396 summer by 0.75 cents/kWh, and the non-summer charge has been decreased by

397 about 0.4 cents/kWh in order to achieve a revenue neutral seasonal rate shift for
398 each Utility. The third step differs somewhat from the residential methodology.

399 **Q. How does the third step differ from the methodology used for the residential**
400 **class?**

401 A. The formerly applicable 2006 bundled service rates were much more numerous
402 than those of the residential class. The Utilities had end use rates for small
403 customers, larger customers, schools, churches, grain drying, municipalities, some
404 were demand based while others were not, some had blocked rates, and some
405 were time-of-use rates. Moreover, it is relatively rare for a residential customer to
406 exceed 60,000 annual kWh of use; however, since the class of DS/BGS-2
407 customers includes customers with demands up to 150 kW, a customer using just
408 under 150 kW could use 60,000 kWh in one month at 55% load factor. These
409 factors make it very difficult, and administratively burdensome, to develop a set
410 of non-residential rates tied to a tail block rate that customers paid in 2006.
411 Instead, summer rates were increased by an amount sufficient to recover the
412 added revenue responsibility shifted from BGS-1. Non-summer prices for the
413 first 2,000 kWh of use were increased by an amount approximately equal to the
414 summer increase. Prices for use over 2,000 kWh were decreased by an amount
415 approximately equal to the non-summer first block revenue gain. On balance, the
416 price adjustments recover the revenue shift from the residential class (BGS-1) for
417 each Ameren Illinois Utility. The details of this calculation are shown on Exhibit
418 2.5.

419 **Q. Why is the non-summer tail block rate for AmerenCIPS discounted by a**
420 **larger amount compared to those proposed for AmerenCILCO and**
421 **AmerenIP?**

422 A. The higher tail block credit was developed in an attempt to provide additional
423 relief to customers that are expected to experience above-average bill impacts in
424 the non-summer season. Specifically, the credit targets customers that were
425 eligible for the formerly applicable space-heat rates.

426 **Q. Why did you choose a non-summer block at 2,000 kWh per month, with**
427 **higher prices for the first 2,000 kWh per month?**

428 A. The Ameren Illinois Utilities examined a series of bill comparisons at various
429 usage profiles and levels. In general, customers using less than 2,000 kWh per
430 month are expected to receive rate decreases or relatively small rate increases.
431 For example, Ameren Illinois Utilities Exhibit 2.1, pages 21-34, illustrates a
432 distribution of customers grouped by the annual percentage increase expected by
433 transitioning from 2006 rates to 2007 rates under the status quo. Implementing a
434 non-summer block at 2,000 kWh, and charging more for the first 2,000 kWh of
435 use, is an attempt to increase rates for customers that have either received a rate
436 decrease or a small increase. Conversely, implementing a declining block non-
437 summer rate recognizes that there are several larger use customers that are already
438 experiencing above-average increases, many of whom may have heated their
439 business with electricity. The objective is for all customers to share in a rate
440 increase, while not causing additional hardship to customers already experiencing
441 above average increases.

442 **Q. Do you have any bill impact examples showing the expected rate changes for**
443 **the various non-residential customer groupings?**

444 A. Yes. Exhibit 2.6 provides a comparison of formerly applicable 2006 rates to
445 those expected in 2007 under the status quo, and those expected if the rate
446 redesign adjustments are adopted. A consistent pattern for all of the Utilities
447 emerges: lower-use customers should expect to see increases from current 2007
448 rates by about 20%, higher summer use customers should expect to see increases
449 from current 2007 rates by about 10%, and higher non-summer use customers
450 should expect to see minor increases (5% or less) or decreases.

451 **Q. Is there a need to adjust rates of BGS-3 or BGS-4 to address bill impact**
452 **concerns?**

453 A. The situation for customers over 150 kW up to 1,000 kW (DS-3) and those using
454 1,000 kW or more (DS-4) is different than that experienced by the residential and
455 small general service classes. Approximately 90% of energy used by DS-4
456 customers is provided through a third-party supplier, and only about 5% energy is
457 provided through BGS-4. Moreover, BGS-4 prices are approximately 2
458 cents/kWh higher on average than those of BGS-1, -2, and -3. Average increases
459 to DS-4 customers, assuming they took BGS-4, are estimated to be about 80% or
460 more (see the Post-Auction Public Report of the Staff, page 23, dated December
461 6, 2006). Customers on BGS-4 are not allowed to switch to an alternate supply
462 until June 1, 2008, and adding costs to this group would appear to run counter to
463 the goal of creating more just and reasonable rates. Likewise, customers currently
464 on BGS-4 had an opportunity to switch to an alternate supplier or take Real Time

465 Pricing service from the Utilities before defaulting to BGS-4 (and about 95% of
466 customers chose not to take BGS-4). By their actions (or inaction) they have
467 affirmed that they are willing to pay BGS-4 rates. Thus, no BGS-4 rate changes
468 are necessary.

469 Prices for BGS-3 are set based on auction bids to serve the loads of all customers
470 under 1,000 kW of demand (BGS-1, -2, -3, and -5). Customers on BGS-3 have an
471 opportunity to switch to service with a third-party supplier or to RTP on short
472 notice (7-45 days). To date, about 1/3 of customer load eligible for BGS-3 is
473 served by a third-party supplier. Adjusting BGS-3 rates higher would serve to
474 accelerate a customer's incentive to switch to a third-party supplier. Thus, any
475 revenue subsidization projected based on today's BGS-3 load would be at risk of
476 falling back to customers targeted to receive the subsidy through the automatic
477 over/under cost recovery mechanism within Rider MV. Conversely, moving
478 BGS-3 rates lower would create an incentive for customers to remain on BGS-3
479 or switch back from a third-party supplier. If this happens, any targeted subsidy
480 provided would grow as customers switch back to service on BGS-3, increasing a
481 deficit to be recovered through the over/under mechanism in Rider MV. In my
482 judgment, neither outcome is desirable. The Ameren Illinois Utilities recommend
483 that BGS-3 rates remain competitively neutral, and no new adjustments are
484 applied as a result of this proceeding.

485 **Q. Are some DS-3 and DS-4 customers experiencing large bill impacts as a**
486 **result of transitioning to new Delivery Services rates?**

487 A. Yes. The Ameren Illinois Utilities are aware that customers with lower load
488 factors, such as grain drying and some pumping districts have been impacted
489 more severely than others. These customers establish high kW demands, but have
490 little kWh usage. Consequently, the demand-based DS-3 and DS-4 charges can
491 be relatively expensive to these customers.

492 **Q. How can bill impacts for these customers be mitigated?**

493 A. The Ameren Illinois Utilities propose that a demand limiter of 2 cent/kWh be
494 imposed within DS-3 and DS-4 tariffs for each of the Utilities. The demand
495 limiter would limit the monthly total cost of the Distribution Demand Charge and
496 Transformation Capacity Charge to 2 cents/kWh. Exhibit 2.7 provides a chart of
497 the number of customers at various average cents/kWh intervals for DS-3 and DS-
498 4, by Utility. An analysis of DS-3 estimated bills indicates that the limiter would
499 create a revenue shortfall of \$688,000, \$304,000, and \$409,000 for AmerenIP,
500 AmerenCIPS, and AmerenCILCO, respectively. An analysis of DS-4 estimated
501 bills indicates that the limiter would create a revenue shortfall of \$65,000,
502 \$64,000, and \$37,000 for AmerenIP, AmerenCIPS, and AmerenCILCO,
503 respectively.

504 **Q. Would the 2 cent/kwhr limit be applicable to all DS-3 and DS-4 customers?**

505 A. No, the limiter would only apply to those customers that limit their total kwhr
506 consumption during the four summer months to 20% or less of their annual kwhr
507 usage. This would insure that customers receiving the limiter would be those that
508 do not make larger than normal contributions to system costs which are typically
509 driven by summer loads.

510 **Q. How would the “20% usage during the summer months” criteria apply?**

511 A. Each existing customer’s eligibility for the limiter would be assessed following
512 the September billing period and be applied for the entire subsequent non-summer
513 billing periods of October through May. The limiter would apply prospectively.
514 New customers with less than 12 months of usage history after the September
515 billing period would not have the limiter applied in the subsequent non-summer
516 period, but would be re-evaluated during the following September billing period
517 and adjusted if their usage indicated that they would have qualified. Such
518 customers would receive a limiter credit in their October bill equal to the amount
519 that would have been limited to 2 cents/kWh in the previous months. No re-
520 evaluation would be done for customers with a full 12 months of usage history at
521 the time of the September eligibility is determined.

522 **Q. How would you propose to recover the revenue shortfall for each DS class?**

523 A. The revenue shortfall may be recovered by increasing the current Distribution
524 Delivery Charges by an equal percentage amount until the revenue shortfall is
525 recovered. Exhibit 2.8, pages 1 and 2, show the Distribution Delivery Charge
526 adjustments needed to ensure revenue neutrality within the DS-3 and DS-4 class,
527 respectively, for each of the three Illinois Operating Utilities. The largest DS-4
528 adjustment is for AmerenCILCO. For primary voltage supply service, an
529 adjustment of \$0.022 per kW is required, or \$220 per month (and \$2,640 per year)
530 for a 10,000 kW customer taking primary voltage supply service. For a customer
531 taking high voltage supply (service usually at 34.5 or 69 kV), the incremental rate
532 adjustment of \$0.005/kW would result in a \$50 per month increase, or \$600 per

533 year. For DS-3, the largest adjustment is again necessary for AmerenCILCO. For
534 primary voltage supply service, an adjustment of \$0.197 per kW is required, or
535 \$98.50 per month (and \$1,182 per year) for a 500 kW customer taking primary
536 voltage supply service. For a customer taking high voltage supply (service
537 usually at 34.5 or 69 kV) using 500 kW, the incremental rate adjustment of
538 \$0.043/kW would result in a \$21.50 per month increase, or \$258 per year. In
539 summary, the adjustment attempts to strike a balance of providing relief to
540 customers who pay relatively high average distribution delivery charges (on a
541 cents/kWh basis), while not burdening other customers.

542 **Q. Why is a 2 cents/kWh limiter reasonable for DS-3 and DS-4 Distribution**
543 **Delivery and Transformation Capacity Charges?**

544 A. Customers taking service under DS-2 pay a cost based customer and meter
545 charge. The Distribution Delivery Charge recovers all other costs attributed to the
546 DS-2 class. Similarly, DS-3 and DS-4 customers pay a cost-based customer and
547 meter charge. The Distribution Delivery and Transformation Charges recover the
548 remaining delivery costs (service under DS-4 also includes a Reactive Demand
549 Charge). The Distribution Delivery Charges for DS-2 service for each of the
550 three Illinois Ameren Utilities is about 2 cents/kWh. Setting the rate limiter for
551 DS-3 and DS-4 provides rate continuity between DS-2 and DS-3 & DS-4
552 customer classes. This is not meant to imply that DS-3 or DS-4 customers with
553 low load factors should never pay more than 2 cents/kWh. Rather, in this time of
554 transition to post 2006 rates, these customers need time to adapt to the newer rate

555 structure. The rate limiter would likely be revisited in future rate cases as to
556 whether it is still needed, or should be changed to a different level.

557 **Q. Do all of the rate re-design proposals mentioned above result in overall**
558 **revenue neutrality for each of the Ameren Illinois Utilities?**

559 A. Yes, consistent with the Commission's order establishing this case, these rate re-
560 designs are revenue neutral.

561 **Impact on Over/Under Cost Recovery Mechanism Within Rider MV**

562 **Q. You previously mentioned the over/under cost recovery mechanism within**
563 **Rider MV. Please explain the basic operation of this tariff provision.**

564 A. The purpose of the over/under recovery mechanism is to ensure that costs paid to
565 suppliers for the BGS-FP (serving BGS-1, -2, -3, and -5) auction product balance
566 with the revenue billed to customers. For example, costs and revenues for the
567 respective period are evaluated, and the over or under recovery of costs, due to
568 differences in customer demand and usage, is recovered in a subsequent period.

569 The amounts paid to suppliers are locked into place for the duration of the auction
570 contracts. About 1/3 of the contracts expire on May 31, 2008. Another 1/3
571 expires on May 31, 2009 and the final 1/3 expires on May 31, 2010. As each
572 contract expires, replacement power must be procured.

573 The weighted average annual cost of the BGS-FP product is \$65.20/MWh. This
574 annual cost is split into a summer and non-summer price. Presently, the average
575 summer price is about \$63/MWh and the non-summer price is about \$66/MWh.

576 **Q. Why is it important to understand the operation of the over/under**
577 **calculation within Rider MV?**

578 A. The over/under calculation is expected to yield relatively minor per kWh
579 adjustments, assuming customers pay the retail supply charges under the 2007
580 status quo. The rate re-design proposals discussed here involve significant
581 adjustments in the revenue expected from customers 1) by season, 2) by usage
582 block, and 3) by customer class. The over/under recovery formula within Rider
583 MV should be modified to ensure that the revenue shifting does not “wash out”
584 through the monthly adjustment factors. For example, \$2 million of BGS revenue
585 has been shifted from January to other months for AmerenCILCO. Assuming that
586 costs and revenues previously matched, the result of the rate redesign would
587 create a deficit of \$2 million for January to be recovered in March. The \$2
588 million deficit divided by March sales would likely produce an estimated under-
589 recovery factor greater than 0.5 cents/kWh for all BGS-FP March usage – a
590 charge greater than the average price reduction expected for the BGS-1 class in
591 March.

592 **Q. Do you have a suggestion on how the monthly over/under calculation could**
593 **be adjusted to minimize the effect of this seasonal “wash-out”?**

594 A. A set of fixed monthly revenue factors could be applied to artificially adjust
595 revenue by an amount sufficient to preserve the planned monthly BGS revenue
596 shifting. These factors are shown in Exhibit 2.9 for BGS-1 and BGS-2, by Utility.
597 For example, BGS-1 revenue for AmerenCILCO is expected to decrease by 0.867
598 cents/kWh in January as a result of rate re-design. Within the monthly over/under
599 calculation examining January revenue, revenue could be adjusted up by 0.867
600 cents/kWh to reflect what would have been received in the absence of rate re-

601 design. The difference will be held for future recovery (in the summer, primarily
602 from BGS-2 customers). The Ameren Illinois Utilities would include interest, at
603 the rate established by the ICC in accordance with 83 Illinois Administrative
604 Code Section 280.70(e)(1), on the differences created by application of the fixed
605 factors. Provided estimated sales are close to actual kWh sales, the over/under
606 calculation should balance by year-end.

607 **Q. Is it reasonable to assume that actual kWh sales and estimated kWh sales**
608 **will always be close?**

609 A. Total residential and small general service customer kWh sales can be predicted
610 with a fairly high amount of certainty, except for the influence of weather.
611 Weather could influence monthly sales by 10% or more.
612 Implementing usage blocks may amplify the effect of weather on expected BGS
613 revenue. For example, if non-summer weather is milder than expected, residential
614 customers that heat their homes with electricity will likely use less energy in the
615 +800 kWh block. Thus, the average unit \$/kWh rate for the non-summer months
616 with mild weather will be higher than that expected under "normal" weather
617 conditions, leading to a over/under "hold back" larger than necessary. The
618 converse would also be true.
619 One non-weather factor also directly influences differences in estimated and
620 actual kWh sales. Customers are eligible to switch from BGS service to energy
621 provided by a third-party supplier. Residential customers have yet to switch;
622 however, more than 10% of DS-2 load is served by third-party suppliers.

623 **Q. Have you evaluated the effect of DS-2 customers switching to third-party**
624 **supply with respect to your over/under calculation?**

625 A. Yes. Holding all other things constant and reducing BGS-2 sales and revenue by
626 10% results in relatively minor revenue shortfall during the non-summer months,
627 but a slightly more significant shortfall in the summer months. For example, with
628 only 90% of BGS-2 load, the over/under calculation would experience a shortfall
629 of about 0.05 cents/kWh. This calculation assumes recovery of the shortfall only
630 from BGS-1 and BGS-2 customers. The actual operation of the over/under
631 calculation would also include any BGS-3 and BGS-5 sales in the determination
632 of the factor. In general, for each 10% point drop in BGS-2 sales, there is a 0.05
633 cents/kWh drop in summer BGS recovery. So if only 60% of DS-2 kWh sales
634 were served under BGS-2, the potential summer shortfall would be about 0.2
635 cents/kWh or less (less because BGS-3 and BGS-5 would also share in the deficit
636 recovery). Exhibit 2.10 illustrates the projected monthly impact of serving only
637 90% of BGS-2 load (10% switching) on the over/under calculation.

638 **Q. Would the monthly factors need to be adjusted periodically?**

639 A. The factors should be evaluated periodically to account for additional switching
640 that may have occurred, and to take into account replacement power contracts and
641 the new weighted cost of power supply.

642 **Timing of Rate Redesign Implementation**

643 **Q. How would implementation of rate redesign changes impact the Ameren**
644 **Illinois Utilities' annual revenue?**

645 A. The revenue impact of changing DS and BGS rates depends on when such
646 changes are implemented. If the changes are implemented on January 1, the
647 impact on annual revenue should be negligible. If changes are implemented on
648 October 1, the price reductions proposed for non-summer use will reduce the
649 Company's revenue. This is primarily true of DS revenue. Ameren Illinois
650 Utilities' Exhibit 2.11 illustrates that on an annual basis, revenue changes are
651 negligible. If DS changes are implemented starting in October, the loss of
652 revenue versus the status quo will reach an expected \$16.9 million (\$5.3 million
653 in October, \$4.9 million in November, and \$6.6 million in December).

654 **Alternate Re-design Scenario**

655 **Q. Do you have a suggested rate design methodology should the Commission**
656 **decide to reduce or eliminate the proposed subsidization of BGS-1 by BGS-**
657 **2?**

658 A. Yes. Similar steps to those outlined in the approach above could be followed.
659 First, the revenue allocation step would be adjusted (or eliminated) to reflect a
660 reduced (or no) subsidy. Next, the tail block non-summer rates would be adjusted
661 upward to reflect the higher "average" increase target for each Utility. Third, the
662 residential summer rate increase limit of 5% over 2007 status quo rates could be
663 relaxed or eliminated. If the subsidy were to be eliminated, raising the residential
664 summer increase from 2007 status quo rates by 12% for AmerenCILCO, about
665 15% for AmerenCIPS, and about 14% for Ameren IP would generate a fully
666 revenue neutral design for the DS/BGS-1 rate class.

667 Next, BGS-2 rates could be reduced in the summer and the 0-2,000 kWh usage
668 block in the non-summer by equal amounts.

669 The results of the BGS-1 adjustments, assuming no subsidy, are shown in Exhibit
670 2.12. A comparison of residential bill impacts, assuming no subsidy from BGS-2,
671 is shown in Ameren Illinois Utilities' Exhibit 2.13. The results of the BGS-2
672 adjustment, assuming no subsidy, are shown in Ameren Illinois Utilities' Exhibit
673 2.14. A comparison of residential bill impacts, assuming no subsidy from BGS-
674 2, is shown in Ameren Illinois Utilities' Exhibit 2.15. The effect of BGS revenue
675 shifting and an estimate of the impact it may have on the monthly over/under
676 calculation within Rider MV is shown in Ameren Illinois Utilities' Exhibit 2.16.
677 The influence of BGS-2 customer switching on the monthly over/under recovery
678 mechanism within Rider MV is shown in Ameren Illinois Utilities' Exhibit 2.17.
679 As may be expected, a rate re-design scenario with no interclass subsidies results
680 in relatively benign impacts on the monthly over/under calculation.

681 **Q. How should rates be adjusted in the future as power supply contracts expire**
682 **and new power supply is purchased, as you previously mentioned?**

683 A. At the time new power supply prices are known, the BGS adjustments proposed
684 herein could be adjusted on a uniform percentage basis. For example, if new
685 power supply contracts result in a decrease of 5% in overall power supply costs
686 for the BGS-FP group, all adjustments could be reduced by 5% as well. A more
687 comprehensive review of bill impact concerns could be undertaken at during the
688 Ameren Illinois Utilities' next delivery services rate case proceedings.

689 **Q. Before concluding your testimony, do you have any additional points that the**
690 **Commission should consider?**

691 A. Yes, throughout this process we have addressed customer impacts and mitigation
692 of high increases in costs for certain types of customers, particularly the home
693 heating customers. I again want to note that the scenarios, including Ameren's
694 preferred approach, are designed to address these immediate customer impacts.
695 In the future, it is advisable that the Commission revisit this rate design, and
696 consider changes that bring rates into alignment with cost causation principles and
697 ultimately send price signals to consumers that will enable them to make positive
698 economic decisions regarding their energy use. As energy, fuel, and
699 environmental costs continue to rise, it is important that we work to reduce
700 subsidies that encourage uneconomic energy consumption.

701 **Q. Does this conclude your testimony?**

702 A. Yes, it does.

703