

ILLINOIS COMMERCE COMMISSION

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DIRECT TESTIMONY

OF

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Submitted On Behalf

Of

AMEREN CORPORATION

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23 Q. **Please describe your educational background.**

24 A. I earned a Bachelor of Science degree in electrical engineering in 1980 from the
25 University of Missouri – Rolla.

26 Q. **Please describe your work experience.**

27 A. I was employed as an Assistant Engineer in the Rate Engineering Department of
28 Union Electric Company in June 1980. My work included assignments relating to
29 the general analyses and administration of various aspects of Union Electric
30 Company's electric, gas, and steam rates. In October 1989, I was appointed
31 Supervising Engineer – Rate Analysis in the Rate Engineering Department of
32 Corporate Planning at Ameren Services Company. In the latter position, I was
33 responsible for meeting the analytical requirements of Union Electric Company's
34 retail gas and electric rates and wholesale electric rates, including load research
35 and various cost of service and rate design studies, as assigned. I was appointed
36 to my present position of Manager of Rate Engineering and Analysis - Regulatory
37 Policy and Planning in March 2003.

38 Q. **Please describe your duties and responsibilities as Manager Rate
39 Engineering and Analysis – Regulatory Policy and Planning.**

40 A. I currently have responsibility for the general policies and practices associated
41 with the day-to-day administration and design of the Ameren Companies' electric
42 and gas rate tariffs, riders and rules and regulations tariffs on file with the Illinois
43 Commerce Commission and, also, similar responsibilities for AmerenUE's
44 Missouri operations. In addition, Rate Engineering and Analysis is responsible
45 for conducting class cost of service and rate design studies and the participation in

46 other projects of a general corporate nature, as requested by the Director of
47 Regulatory Policy and Planning.

48 **Q. What is the purpose of your testimony?**

49 A. The primary purpose of my testimony is to present and explain various aspects of
50 the development of rate tariffs for the providing of power service to the Ameren
51 Companies' retail electric service customers at the end of the mandatory transition
52 period under the Customer Choice Law of 1997. More specifically, these tariffs,
53 along with Transmission Service ("TS") and Delivery Service ("DS") tariffs, will
54 provide retail customers of these operating companies with a continuation of
55 bundled service (i.e., complete service from production to transmission to
56 distribution) via a combination of separate tariffs for power, transmission, and
57 distribution service. In his direct testimony, Mr. Craig D. Nelson provides a
58 complete overview of the Companies' proposal and its place in the statutory and
59 regulatory framework.

60 **II. BGS RATES AND RATE DESIGN DISCUSSION**

61 **Q. Please provide a brief description of the power supply product(s) for which
62 post-2006 rates for power need to be developed.**

63 A. As discussed in the testimony of Mr. Nelson and Mr. James Blessing, the Ameren
64 Companies plan to conduct a "New Jersey style" auction or competitive bidding
65 process for the supply of power to all of its retail electric customers post-2006.
66 Bidders will be required to bid on uniform tranches of power supply for three
67 products: (1) full requirements power at "fixed" prices for the aggregated load of
68 all Illinois retail electric customers with individual demands of less than 1,000

69 kilowatts of AmerenCIPS, AmerenCILCO, and AmerenIP (i.e., within the
70 “Ameren Footprint”), (2) full requirements power at “fixed” prices for the
71 aggregated load of all Ameren Footprint customers with individual demands equal
72 to or greater than 1,000 kilowatts and (3) Real Time Pricing power for all Ameren
73 Footprint customers with individual demands equal to or greater than 1,000
74 kilowatts.

75 **Q. What were some of the Companies’ goals and objectives in the development**
76 **of rates for the providing of power to its retail electric customers post-2006?**

77 A. The Ameren Companies operate as Integrated Distribution Companies (“IDCs”)
78 under the Commission’s rules, and are not expected or required to own any
79 significant generation resources. As Mr. Warner Baxter and Mr. Nelson explain,
80 the rates for power within the Ameren Footprint must allow for full, timely, and
81 precise recovery of all costs associated with the procurement of power and energy
82 needed to serve Ameren Footprint customers. This recovery is critical to both the
83 financial health of the Ameren Companies, and also to the development of a
84 robust competitive retail power market in Illinois. Absent recovery of actual
85 power procurement costs from customers, the financial health of these utilities
86 could be unduly harmed.

87 My testimony is more focused on a second goal: namely, to design class rates
88 that reflect cost causation and equitable cost recovery principles, with a proper
89 consideration of equity and fairness to all customer classes. As stated earlier,
90 total costs associated with procuring power from the market must ultimately be

91 recovered, and the notion of overcharging one customer class in order to subsidize
92 another class is unfair to the customer class or classes being overcharged.
93 Additionally, cost based rates promote the cost effective utilization of electricity
94 by customers. To make appropriate decisions regarding the most efficient and
95 effective use of electricity, as well as the acquisition of electrical consuming
96 equipment, customers require accurate and appropriate price signals through
97 electric rates.

98 While I mentioned the importance of rates providing for the full recovery of
99 power procurement costs earlier from a market perspective, cost based class rates
100 are essential for the development of a competitive power market, because
101 individual class rates for power compete with prices from Alternative Retail
102 Electric Suppliers ("ARES" or "RES"), alternative fuels, and co-generation.
103 Accordingly, the utility's class rates must not provide a non-cost based advantage
104 for customers to elect power service from an Ameren Company, to the detriment
105 of competitive providers.

106 **Q. What is the Ameren Companies' proposal with regard to rates for power for**
107 **customers within the Ameren Footprint?**

108 A. The Ameren Companies are proposing the uniform application of "fixed" power
109 rates by service classification across the entire Ameren Footprint in Illinois. In
110 other words, customers of specific service classifications (e.g., residential) will be
111 billed under the same power rates regardless of which Ameren Company serves
112 them. Additionally, all customers within the Ameren Footprint will be given a

113 choice between a "fixed" price product or a Real Time Pricing ("RTP") product
114 for power service.

115 The uniform application of power rates for the different "fixed" products
116 across the entire Ameren Footprint is consistent with the bidding of the entire
117 Ameren Footprint in the competitive power procurement or auction process,
118 promotes simplicity and ease of customer understanding, promotes the goal of
119 total uniformity of tariff application, and results in more efficient and effective
120 administration of the Ameren Companies' retail electric rates throughout the
121 Illinois service territories. Additionally, as discussed later in this testimony, the
122 resultant power rates equitably recover costs associated with capacity service
123 among and within customer groups. The Companies' energy charges under its
124 RTP products may vary modestly across Ameren's three control areas. Later in
125 this testimony, I will provide additional discussion on RTP rates.

126 **Q. Please describe the proposed generation service offerings for customers who**
127 **elect "fixed" price power service from an Ameren Company post-2006.**

128 A. Consistent with Ameren's competitive procurement auction ("CPA") for power
129 procurement post-2006, which Mr. Nelson and Mr. Blessing describe, the Ameren
130 Companies are proposing to designate their two Basic Generation Service
131 ("BGS") offerings of "fixed" price power service as: 1) Rider BGS – Basic
132 Generation Service (Applicable to Customers with Demands Less than 1,000
133 kilowatts and 2) Rider BGS-L – Basic Generation Service – Large (Applicable to
134 Customer with Demands Equal to or Greater than 1,000 kilowatts. These two
135 riders are set forth in Resp. Exhibit 5.1.

136 **Q. Please describe the proposed RTP offerings for customers.**

137 A. The Ameren Companies are bidding only one RTP product for customers with
138 demands equal to or greater than 1,000 kilowatts; however, they will, via “rate
139 design” afford customers with demands less than 1,000 kilowatts the opportunity
140 to elect billing for power under a RTP rate. As a result, the Companies are
141 proposing to designate their two offerings of Real Time Pricing as: (1) Rider RTP
142 – Real Time Pricing (Applicable to Customers with Demands Less than 1,000
143 kilowatts) and (2) Rider RTP-L – Real Time Pricing Large (Applicable to
144 Customers with Demands Equal to or Greater than 1,000 kilowatts). These
145 designations align with the previously mentioned BGS Riders with regard to
146 naming convention and should promote ease of customer understanding. The two
147 RTP riders are set forth in Resp. Exhibit 5.2.

148 **Q. Will any of the previously mentioned BGS or RTP riders contain actual**
149 **prices or rate values for power service?**

150 A. No. The Ameren Companies are proposing that all pricing of power service be as
151 prescribed in the Market Value Rider – Rider MV as explained in the direct
152 testimony of Mr. Robert Mill. All BGS and RTP tariffs “point to” Rider MV for
153 the determination of prices or rates BGS.

154 II. Service Classifications, Rate Design and Rate Application Discussion

155 **Q. Please summarize the proposed service or rate classifications for the**
156 **Companies’ BGS and RTP offerings.**

157 A. The following table delineates our proposed BGS and RTP offerings:

158 Table 1.

Service Classification	Rider BGS	Rider RTP
Residential Service	BGS (BGS-1)	RTP (RTP-1)
Small General Service	BGS (BGS-2)	RTP (RTP-2)
General Service	BGS (BGS-3)	RTP (RTP-3)
Large General Service	BGS-L (BGS-4)	RTP-L (RTP-4)
Dusk to Dawn Lighting Service	BGS (BGS-5)	N/A

159

160 **Q. Please describe the general rationale supporting these service classifications.**

161 A. In general, the development of rate or service classifications should reflect intra-
162 class homogeneity and, also, limit the ability of customers to switch or migrate
163 from one rate to another. That is, customers with comparable load and service
164 characteristics should be included in the same class. Customers within these
165 classes are fairly homogenous in load, load characteristics and metering
166 installations.

167 Also, from a strategic perspective, the Companies expect to align or synchronize
168 their DS rates with those in Table 1 prior to the effective date of the BGS and
169 RTP tariffs. This alignment will promote ease of customer and Commission Staff
170 understanding in matching the applicable BGS and RTP service classifications
171 with the corresponding DS rates. It should be noted that all retail customers must
172 be served under Ameren's DS rates.

173 **Q. Please provide an overview of post-2006 BGS class rate design.**

174 A. The proposed BGS class rates for post-2006 consist of consumption-based
175 charges for capacity and energy service. We are not proposing the use of demand
176 charges for any of the BGS offerings. The nature of today's commoditized
177 wholesale markets for power supports this type of rate design as it tracks cost

178 incurrence. In recent years, the pricing of power has shifted from a fixed-variable
179 cost-based method using actual embedded power plant investment and running
180 costs, to a market-based approach that has introduced the trading of uniform
181 blocks of power supply offered through commodity exchanges and hubs. In
182 essence, the market has shifted the capacity-related generation costs into the
183 "energy price" on which power is traded. Our use of a rate translation prism (to
184 be discussed later in this testimony) that utilizes customer usage data, bid price
185 and estimates of other components of costs, as contrasted to traditional
186 jurisdictional retail class cost of service and rate design principles, demonstrates
187 that there is no need for additional granularity (of adding a demand charge) in the
188 BGS rate classes. The energy-only rate design resulting from the application of
189 the rate translation prism adequately addresses cost causation and equitable cost
190 recovery principles.

191 To contrast the decline of capacity valuation in today's wholesale markets to
192 historical periods, the price for regulatory capacity is around \$1-\$2 per kW-month
193 versus the \$6-\$9 per kW-month value likely reflected in current bundled prices
194 that were set one or more decades ago. Consequently, assuming this trend
195 continues, for at least the near future, retail pricing for power supply will be on a
196 per kWh basis, a significant difference from the capacity component embedded in
197 historical bundled power service rate structures.

198 Q. **Do current power markets differentiate energy prices by season and/or time**
199 **of day?**

200 A. Yes. Today's power markets adequately reflect differing costs by rating or
201 pricing period. As a result, prices are typically quoted by month with additional
202 delineation of on-peak versus off-peak rating period or down to the hourly level,
203 where required.

204 Q. **Have the Ameren Companies reflected market price delineation by season in**
205 **all of its proposed BGS offerings?**

206 A. Yes. Each of the BGS offerings contains seasonal pricing for power. Consistent
207 with the Midwest Independent System Operator, Inc. ("MISO") of which the
208 Ameren Companies are members, we have designated the months of June, July,
209 August, and September as the summer billing season with all remaining months
210 being designated as non-summer. Additionally, BGS energy rates for larger
211 customers (>1,000 KW) contain the same seasonal differentiation along with on-
212 peak versus off-peak billing provisions. The Ameren Companies are proposing
213 that on-peak hours be designated as weekdays 6:00 a.m. to 10:00 p.m. Central
214 Prevailing Time. All other hours, including weekends and certain North
215 American Electric Reliability Council ("NERC") designated holidays, are off-
216 peak. This on-peak hours designation is consistent with MISO's summer
217 designation of the on-peak period as weekdays 6:00 a.m. to 10:00 p.m. Eastern
218 Standard Time. However, while MISO's Eastern Time Zone on-peak period
219 designation does not consider Daylight Savings Time, its the Central Time Zone
220 does. As a result, our proposed non-summer on-peak hours are one hour "behind"

221 the comparable MISO hours. Clearly, there is no perfect match between our
222 proposed on-peak period and MISO's; however, we understand the importance of
223 customer understanding of rates and also ease of rate administration. Our
224 proposed use of a consistent "local zone" time period for on-peak designation
225 throughout the year promotes understanding and administration. Also, the use of
226 the more critical summer MISO on-peak designation on a year-round basis does a
227 better job of recognizing higher costs during on-peak periods. Again, all other
228 hours, including weekends and NERC designated holidays, are off-peak.

229 **Q. Please describe Service Classification BGS-1 – Residential Service.**

230 A. Service Classification BGS-1 will apply to all residential customers who elect full
231 requirements service from the Companies, commonly referred to as "bundled
232 service", and who satisfy the applicable requirements for Residential Service.
233 Customers within this classification will require energy-only metering and basic
234 charges for BGS service in this classification are energy-only, with seasonal
235 differentiation and a declining block rate for non-summer energy.

236 **Q. Considering your earlier statement of uniform blocks of power supply
237 offered through commodity exchanges and hubs, why are you proposing a
238 declining block rate for the Residential non-summer BGS fixed rate?**

239 A. Historically, many vertically integrated utilities utilized declining block rates to
240 track the proportionately lower costs of increased volumes through certain fixed
241 assets. This declining block pattern followed the trend of per unit costs going
242 down as volume goes up. Both AmerenCILCO and AmerenUE (Metro East,
243 which is being transferred to AmerenCIPS) have this form of non-summer rate

244 design within their current bundled residential tariffs. Typically, customers with
245 usage in the non-summer lower priced block have electric space heating.
246 AmerenCIPS has lower end-use rates for residential non-summer space heating
247 usage, while AmerenIP has both a declining block rate and lower end-use rates for
248 non-summer space heating usage. At present, the Ameren Companies have
249 approximately 820,000 residential customers or 78 percent of the total who are
250 either subject to blocked non-summer residential rates or who are billed under
251 end-use rates for electric space heating. AmerenUE's declining block is set at 600
252 kWh, AmerenCILCO's is set at 930 kWh, and AmerenIP's is at 300 kWh.
253 AmerenIP's residential service further provides for a lower rate for non-summer
254 space heating usage which is defined as "all kWh used during the billing period in
255 excess of Non-Space Heat Usage". Non-Space Heat Usage is "all kWh used
256 during the billing period up to the product of the average daily usage in the two
257 billing periods with the lowest non-zero kWh user per day occurring during the 12
258 consecutive billing periods ended with the current billing period multiplied by the
259 number of days in the current billing period, but not less than 13 kWh per day".
260 AmerenCIPS's Rider 5 -- Residential Electric Space Heating Service provides
261 blocking at the 0 - 400kWh, 401-800 kWh and all over 800 kWh levels. The non-
262 spacing heating customer's average non-summer use for AmerenCIPS, AmerenIP,
263 AmerenUE, and AmerenCILCO is 696 kWh, 678 kWh, 800 kWh and 755 kWh,
264 respectively.
265 Considering the current levels for each of the Ameren Companies, a conservative
266 level of 800 kWh was utilized to establish the initial block for residential non-

267 summer use. This conservative approach recognizes the current existence of
268 lower rates for non-summer usage above the class average for non space heating
269 residential customers for a large number of customers within the residential use
270 category while, at the same time, renders it less likely that these non-summer
271 “high use” customers will be billed for non-space heating usage at the lower non-
272 summer trailing block rate. Additionally, the continuation of this form of rate
273 design for such a large subset of the residential class will help to mitigate
274 concerns of customer rate impact, if any.

275 **Q. What level are you proposing for the declining or trailing block of the**
276 **Residential non-summer BGS fixed rate?**

277 A. I am proposing that the Residential non-summer trailing block rate be set at
278 approximately the same level as the non-summer off-peak rate for the BGS-3
279 classification. To achieve this result, the Residential non-summer trailing block
280 per unit cost in the rate translation prism was set at the off-peak non-summer per
281 unit cost for the BGS-3 classification as calculated in the prism.

282 **Q. Please explain the rationale of setting this rate equal to the off-peak**
283 **non-summer per unit cost for the BGS-3 General Service classification.**

284 A. As discussed previously, with the appropriate blocking levels, the objectives for
285 determining the price differential between the first and second blocks of the
286 residential non-summer rate were: (a) rate continuity and (b) rate impact
287 mitigation. Initially, I reviewed the current residential non-summer block price
288 differentials of the Ameren Companies and calculated a simple average of
289 approximately 45%. Table 2 below demonstrates that the existing block price

290 differentials do not vary significantly among the Ameren Companies. However,
 291 considering the nature of today's commoditized wholesale markets for power
 292 mentioned earlier, the establishing of a trailing block at a level of 45% of the
 293 initial block would be inequitable. The calculated value for the BGS-3 off-peak
 294 non-summer per unit cost reflects the costs associated with additional off-peak
 295 usage of residential space heating. Additionally, the use of this value is not likely
 296 to produce a 55% discount from the Residential first block rate. Also, it should be
 297 noted that Ameren's proposal mitigates energy costs only. That is, the existing
 298 bundled price differentials represent a discount on production, transmission and
 299 distribution, while Ameren's proposal only contains a differential for power.
 300 Therefore, this proposal "waters down" the average of the existing differentials.

301 Table 2

	AmerenCILCO	AmerenCIPS	AmerenIP	MetroEast	Average
Initial Block	6.618¢/kWh	6.988¢/kWh	5.947¢/kWh	5.880¢/kWh	6.358¢/kWh
Trailing Block	3.521¢/kWh	3.350¢/kWh	2.499¢/kWh	2.175¢/kWh	2.886¢/kWh
% Differential	53%	48%	42%	37%	45%

302
 303 **Q. Please describe Service Classification BGS-2 – Small General Service.**

304 A. Service Classification BGS-2 - Small General Service will apply to all
 305 non-residential customers with individual metered demands of less than 150
 306 kilowatts or limited un-metered energy service customers who elect full
 307 requirements power service from an Ameren Company and who satisfy all of the
 308 other Availability/Applicability provisions of Ameren Company's Delivery
 309 Service (DS – Rate 2) tariff. Customers within this classification will require
 310 energy-only metering and basic charges for BGS service in this classification are

311 energy-only with seasonal differentiation. As stated earlier, there are a few
312 customers within this class with limited un-metered service. The Companies will
313 use estimated monthly energy consumption for BGS billing of these customers.

314 **Q. Are the Companies proposing a non-summer declining block rate for this**
315 **customer class as is being proposed for the residential class?**

316 **A.** No. While the existing bundled rate structures of the Ameren Companies
317 generally contain lower rates for “space heating” customers, the rationale or logic
318 used to establish the block for the residential class would be inappropriate for the
319 BGS-2 class. The individual usage of customers within the residential customer
320 class does not vary in magnitude as significantly as individual usage within the
321 BGS-2 class. The BGS-2 class contains customers that are generally
322 homogeneous in load patterns; however, there exists significant diversity in the
323 magnitude of the loads of an individual customer within this class. For example,
324 a small hair styling business with electric heat and served under BGS-2 may have
325 average monthly non-summer energy usage in the 1,000 – 2,000 kilowatt-hour
326 range, while a large fast food restaurant with or without electric may have average
327 non-summer monthly usage in the 20,000 - 30,000 kilowatt-hour range. Such
328 significant variations in average monthly usage render the development of a
329 blocking level and associated lower block non-summer rate to be arbitrary. As a
330 result, a declining or trailing block non-summer rate is not being proposed for this
331 class. Further, with this proposed rate design consisting of basic seasonal energy
332 charges only (and no declining block charges), there is a greater likelihood that
333 these customers will be pursued by marketers with a variety of rate/price options.

334 Q. **How do you plan to administer the requirement that customers within**
335 **Service Classification BGS-2 remain at demand levels less than 150**
336 **kilowatts?**

337 A. The Ameren Companies will install a “check” demand meter on any customer
338 within Service Classification BGS-2 whenever the customer’s monthly kilowatt-
339 hours exceed 37,000 kilowatt hours. This level equates to a load factor of
340 approximately 34%, noticeably lower than the class average of approximately
341 50%. If the “check” meter registers a demand equal to or greater than 150
342 kilowatts, then the customer will be moved to Service Classification BGS-3 for a
343 *minimum term of one year, unless the customer opts for the RTP rate.*

344 Q. **Please describe further Service Classification BGS-3 – General Service.**

345 A. Service Classification BGS-3 will apply to all customers with individual metered
346 demands ranging from 150 kilowatts to less than 1,000 kilowatts and who elect
347 full requirements power service from the Ameren Companies and who satisfy all
348 of the other applicable requirements for Intermediate Service of the Delivery
349 Service (DS-3) tariff. Customers within this classification will require Time of
350 Day (“TOD”) energy and demand metering and basic charges for BGS service in
351 this classification are TOD energy with seasonal differentiation.

352 Q. **Please describe Service Classification BGS-4 – Large Service.**

353 A. Service Classification BGS-4 - Large Service will apply to all customers with
354 individual metered demands of at least 1,000 kilowatts and who elect full
355 requirements service from one of the Companies during an “Open Enrollment
356 Period,” and who satisfy all other applicable requirements for Large Service (DS-

357 Rate 4). Customers within this classification will require hourly load profile
358 energy and demand metering and basic charges for BGS service in this
359 classification are TOD energy with seasonal differentiation.

360 **Q. Please describe the “Open Enrollment Period” for this service.**

361 A. As described in the testimony of Mr. Blessing, within 30 days of the results of the
362 auction, DS-4 customers may opt for a one year commitment for power service
363 under BGS-4. Customers electing this option must provide the Ameren
364 Companies with a “wet” signature to verify the selection of BGS-4 for power
365 service.

366 **Q. Please describe Service Classification BGS-5 – Dusk to Dawn Lighting
367 Service.**

368 A. Service Classification BGS-5 – Dusk to Dawn Lighting Service will apply to all
369 un-metered outdoor dusk to dawn lighting service automatically controlled by
370 electronic photocells and who elect full requirements power service from the
371 Company and who satisfy all other applicable requirements for either Private
372 Outdoor Area Lighting (DS-5) or Municipal Outdoor Lighting (DS-6) Service.
373 The Ameren Companies have established a separate classification for this type of
374 lighting service to recognize the unique load characteristics of photocell
375 controlled lighting. Over the years, the Ameren Companies have compiled data
376 that yields the determination of the hours of operation by month for the
377 predictable and “constant” load of photocell controlled lights and, therefore, from
378 a cost causation and equitable cost recovery perspective, it was logical to create a
379 class consisting solely of photocell controlled outdoor area lighting. The loads of

380 non lighting customer classes are not nearly as predictable or constant, thereby
381 further supporting the need for a separate rate class.

382 **III. RATE TRANSLATION DISCUSSION**

383 **Q. With regard to the fixed price power product, you earlier stated that the**
384 **auction process would produce a single clearing price for customers with**
385 **individual demands less than 1,000 kilowatts and a separate single clearing**
386 **price for customers with individual demands greater than 1,000 kilowatts.**
387 **How do you propose to translate these single winning bid prices from the**
388 **auction processes into BGS rates for the respective customer groups?**

389 A. One of the simplest ways to pass these prices on to customers would be billing all
390 energy of customers within these two fixed price products at the winning auction
391 price for the respective product. While such a billing approach would recover the
392 Ameren Companies' total costs of power via the bid or auction process, it would
393 not do so in an equitable and cost-causative manner. To accomplish the recovery
394 of these costs in an equitable and cost-causative manner, we have customized or
395 tailored a "translation tool" or "prism" utilized in New Jersey to develop class
396 rates for retail customers of Public Service Electric and Gas ("PSE&G").

397 **Q. Please explain.**

398 A. We are utilizing the underlying principles of the PSE&G tool, as adjusted to
399 reflect Ameren Footprint and MISO specifics. The first step in the process is to
400 develop, annually before each auction, class seasonal and/or TOD multiplicative
401 factors. These multiplicative factors are developed from the Rate Translation
402 Prism ("Prism"). The Prism combines forward market data for energy and

403 capacity with historical class load data, class historical sales, losses, and where
404 applicable, class blocking data to develop BGS class load-weighted seasonal
405 and/or TOD per unit costs and total system average load-weighted per unit cost.
406 The resulting multiplicative factors are the ratios of the class load-weighted
407 seasonal and/ or TOD per unit costs to the total system average load-weighted per
408 unit cost. The Ameren Companies' "Prism" spreadsheets are attached as Resp.
409 Exhibit 5.3.

410 The forward market data for energy and capacity, historical load data and class
411 historical sales utilized in the Prism will be updated annually prior to each
412 auction. Tables 1 – 16 of the Resp. Ex. 5.3 are the spreadsheets that produce the
413 resulting multiplicative factors. Tables 1-13 are the same for each BGS service
414 classification and Tables 14-16 are the same for each fixed price auction product.

415 **Q. Please explain Table No. 1 of Resp. Ex. 5.3.**

416 A. Table No. 1 contains input data representing the percentage of on-peak energy, by
417 month, by each Ameren Company, and for each proposed rate schedule. The on-
418 peak period as used in this table is defined as the 16 hour period from 6:00 a.m. to
419 10:00 p.m. CPT, Monday through Friday. All remaining weekday hours and all
420 hours on weekends and holidays recognized by the NERC are considered off-
421 peak. For illustrative purposes, the values in this table for each month are the
422 average on-peak percentages as calculated from the most recent load research data
423 of the Ameren Companies. We are proposing to update this data annually xx
424 business days prior to the first day of the auction. Subsequent annual revisions
425 will utilize average peak usage percentages based on load profile data for the 24

426 consecutive monthly billing periods extending through the monthly period ending
427 no later than five (5) months prior to the earliest possible auction commencement
428 date. Utilizing a two (2) year period will reduce the variability of weather effects
429 on the percentages from any single year. Should load profile data be unavailable
430 for the 24 consecutive months prior to the initial auction, we will utilize the most
431 recent 12 months of data.

432 **Q. Please explain Table No. 2 of Resp. Exhibit 5.3.**

433 A. Table 2 is a data input placeholder for percentage use during on-peak and off-
434 peak periods that would be different from the 16 hour period discussed earlier in
435 Table No. 1. Table 2 is necessary only if there is a need to use on-peak billing
436 periods that differ significantly from those used for inputting of forward market
437 prices, as discussed below. As stated earlier, the Ameren Companies' proposed
438 on-peak billing hours are the same for the summer months and differ by one hour
439 for the non-summer months. The slight shift of one hour during the non-summer
440 months is not expected to have any material impact on the resultant pricing of the
441 BGS services.

442 **Q. Please explain Table No. 3 of Resp. Exhibit 5.3.**

443 A. Table No. 3 is a data input table which contains the average energy usage in each
444 monthly billing period based on energy delivered to each BGS service
445 classification, as expanded for losses, for the Ameren Companies in the 24
446 consecutive monthly billing periods extending through the monthly billing period
447 ending no later than five (5) months prior to the earliest possible auction
448 commencement date. For illustrative purposes, in this filing, Table No. 3 is

449 populated with historical calendar month sales of the Ameren Companies for the
450 calendar year 2003, by month and by each proposed BGS rate classification at the
451 bulk supply system level.

452 **Q. Please explain Table No. 4 of Resp. Exhibit 5.3.**

453 A. Table No. 4 contains the forwards prices for energy, by month and by time period
454 (On-Peak and Off-Peak) corresponding to the applicable annual period for which
455 retail supply charges are being determined. In this filing these forward prices are
456 not necessarily the view of the Ameren Companies but, instead are meant to serve
457 only as proxies to help facilitate or illustrate the results of the use of the Prism.
458 We are proposing the following procedure for determining On-Peak and Off-Peak
459 Energy Market Forwards prior to the initial auction and subsequent annual
460 revisions.

461 A monthly Peak Energy Market Forward Price (PE_{mo}) and monthly Off-Peak
462 Energy Market Forward Price (OE_{mo}) in dollars per megawatt-hour (\$/MWh), will
463 be determined from the market data from forward contracts for electric power
464 delivered into the MISO's Central Illinois Hub from 6:00 a.m. to 10:00 p.m.
465 Monday through Friday, excluding NERC holidays. Should the MISO energy
466 market be delayed or develop more slowly than anticipated, we will utilize the
467 Into Cinergy Hub as an alternative source. A separate PE_{mo} and OE_{mo} will be
468 determined for each relevant calendar month in the respective BGS rate period.
469 The Ameren Companies will use the Intercontinental Exchange reporting service
470 or Platt's Energy Trader as the source of the market data, but may include
471 additional or different electronic exchanges or reporting services in the future as

472 allowed by the Commission. The market data will be obtained daily by the
473 Companies from these sources' end-of-day reports to obtain a representation of
474 the market for each of the forward contracts for the respective auction period.
475 The market data will be obtained on each of the ten consecutive business days
476 ending on or before the date ninety days prior to the earliest possible auction
477 commencement date.

478 In the absence of market data for forward contracts with terms for individual
479 months, market data for forward contracts with longer terms will be utilized. In
480 the event no data exists for any given month in the off-peak period for which data
481 is to be obtained, we will use ratios of actual off-peak to on-peak MISO locational
482 marginal prices for the Ameren control areas for the most recent historical month
483 corresponding to the month for which no forecast data exists. In the event that no
484 data exists for any given month in the on-peak period for which data is to be
485 obtained, we will use data for a more recent comparable month.

486 **Q. Please explain Table No. 5 of Resp. Exhibit 5.3.**

487 A. An adjustment of the forward prices contained in Table No. 4 must be corrected
488 for the effects, if any, of transmission congestion on the MISO system between
489 the MISO Central Illinois Hub and the Ameren zone where the BGS supply will
490 be utilized. Table No. 5 contains an estimate of the average congestion factors,
491 by month and by time period. Since the MISO system is in its infancy stages and
492 thus has no useful history of such congestion, we have set this adjustment equal to
493 "1" in this filing. The setting of this factor to "1" removes any consideration of
494 congestion for this filing. We may, in subsequent annual revisions, include an

495 estimate of the average congestion factor should such congestion in the MISO
496 system become a known quantity. Approval of a charge in the average congestion
497 factor would be sought from the Commission.

498 **Q. Please explain Table No. 6 of Resp Exhibit 5.3.**

499 A. Table No. 6 contains, for each of the Ameren Companies, the factors utilized for
500 average distribution system losses and unaccounted for supply by proposed BGS
501 rate schedule with adjustments to reflect delivery voltages. Currently, the loss
502 factors are those shown in each of the Ameren Companies' applicable Delivery
503 Services tariffs. Such loss factors are multiplied by metered customer usage to
504 calculate the expected metered consumption at the bulk system level. Of course,
505 these loss factors may be updated or adjusted from time to time as approved by
506 this Commission.

507 **Q. Please explain Table No. 7 of Resp. Exhibit 5.3.**

508 A. Table No. 7 is the calculation of, for each of the Ameren Companies, the energy-
509 only per unit costs by proposed BGS rate, time period, and season. These values
510 are the seasonal and time period average costs per MWh as measured at the bulk
511 system based on monthly time period weights from Table No. 1 and forwards
512 prices from Table No. 4 as corrected for congestion (Table No. 5). These average
513 per unit costs do not include the costs associated with ancillary services,
514 generation obligations or transmission costs, which will be considered in
515 subsequent calculations.

516 **Q. Please explain Table No. 8 of Resp. Exhibit 5.3.**

517 A. Table No. 8 indicates, for the Ameren Companies, the total value of the average
518 BGS energy-only costs, by proposed BGS rate classification, time period and
519 season. These values are the results from multiplying the unit costs from Table
520 No. 7, the monthly time period weights from Table No. 1 and the total sales to
521 customers from Table No. 3. These seasonal and rating period costs are used in
522 Table No. 9 to calculate *per unit costs at the customer's meter*.

523 **Q. Please explain Table No. 9 of Resp. Exhibit 5.3.**

524 A. Table No. 9 shows the resulting Ameren Companies' composite rate class load
525 weighted seasonal and TOD per unit energy-only costs at the customer's meter
526 and are used to develop the rate multipliers and seasonal payment factors
527 discussed later in this testimony. These values result from dividing the sum of
528 each of the Ameren Companies' average BGS energy-only seasonal, TOD and
529 total costs from Table No. 8 by the composite applicable seasonal, TOD, or total
530 MWh use at the customer's meter.

531 **Q. Please explain Table No. 10 of Resp. Exhibit 5.3.**

532 A. Table No. 10 sets up the data necessary for the inclusion of the costs of the
533 generation and transmission obligations. The top portion of Table No. 10 shows,
534 for each of the Ameren Companies, the total obligations by proposed BGS rate
535 classification. Over the years, the Commission has approved the use of peak
536 loads for the allocation of fixed costs associated with generation and transmission
537 assets. As a result, we utilized the average of the four summer coincident peaks
538 for each class to allocate similar market-based fixed costs in this filing. The use of

539 four coincident peaks does a fair job of recognizing the significant multiple peaks
540 on the Companies' system. The middle portion of this table shows the number of
541 summer and non-summer days and months that are used in this analysis. The
542 bottom portion of this table shows the annual cost for transmission service and a
543 seasonally differentiated market price of generation capacity. In this filing, the
544 cost of transmission service is set to zero. It is our intent that the bid prices will
545 exclude network transmission service and that these costs will be charged
546 separately to retail customers through application of a new transmission cost
547 recovery tariff that the Ameren Companies plan to file in their next DS rate
548 filings. Currently, there is not a MISO capacity market in place; therefore, we are
549 proposing to use an estimate of the current wholesale market prices for capacity in
550 PJM as a proxy. The Ameren Companies will use MISO capacity market prices
551 in the first filing of the Prism after such market exists.

552 **Q. Please explain Table No. 11 of Resp. Exhibit 5.3.**

553 A. Table No. 11 are the costs of ancillary transmission services to be included in the
554 winning bid price. We proposes that ancillary services costs be based on
555 averaging historical annual ancillary transmission services costs incurred in the
556 provision of electric power supply for the 12 months ending no later than 90 days
557 prior to the auction commencement date. Since there is no history of MISO
558 ancillary costs, we have chosen, in this filing, to utilize the average \$ per MWh
559 ancillary services cost as determined by PSE&G in the most recent PJM auction
560 which is meant to serve only as a proxy to help facilitate and illustrate the results
561 of the use of the Prism.

562 **Q. Please explain Table No. 12 of Resp. Exhibit 5.3.**

563 A. Table No. 12 shows the result of the allocation of both transmission and
564 generation costs on a per MWh basis to the proposed BGS rate classifications.
565 These values are the result of, for each proposed BGS rate, dividing the sum of:
566 (1) each of the Ameren Companies' average four coincident peaks from the upper
567 portion of Table No. 10, multiplied by (2) the seasonal daily capacity price,
568 multiplied by (3) the number of days per the seasonal period per the middle
569 portion of Table No. 10, by the sum of each of the Ameren Companies' seasonal
570 MWh at the customers' meters.

571 **Q. Please explain Table No. 13 of Resp. Exhibit 5.3.**

572 A. Table No. 13 contains the overall supply cost computation by rate classification,
573 by summer and non-summer periods, and by on-peak and off-peak periods within
574 those seasons as applicable. The top portion of Table No.13 is the resulting BGS
575 class load-weighted seasonal and/or TOD per unit costs and total system average
576 load-weighted per unit cost of the inclusion of the transmission, generation
577 capacity, and ancillary services costs to the energy-only costs shown in Table No.
578 9. These seasonal and time differentiated per unit costs become the numerator in
579 the formulas that determine the multiplicative ratios in Table No. 14. Based on
580 the assumptions utilized in the above tables, the bottom portion of this table
581 shows, for each BGS service classification the total estimated "all-in" BGS costs
582 to be recovered on an energy-only basis and the average per unit costs as
583 measured at the customer meters or the bulk system.

584 Q. **Please explain Table No. 14 of Resp. Exhibit 5.3.**

585 A. This table is one of the most critical tables in the Prism. The upper portion of the
586 table summarizes, for each BGS auction product, the total estimated costs of the
587 BGS rate classes based on the inputs utilized in Tables 1-13 for each class and the
588 resulting average "all-in" per unit cost measured at the customer meters and the
589 bulk system. The middle and lower portions of this table is the resulting ratio
590 (multiplicative factors) of each of the individual rate element cost components
591 from Table No. 13, for each BGS rate class, to the overall all-in costs as measured
592 at the bulk system from the top portion of this table.

593 Q. **Please explain Table No. 15 of Resp. Exhibit 5.3.**

594 A. Table No. 15 shows the calculation of the total BGS costs, by season utilizing the
595 seasonal customer usage from Table No. 3, adjusted for losses from Table No. 6,
596 and the all-in unit costs from Table No. 13. The lower portion of this table
597 indicates the relative percentage of total costs by season and the overall average
598 all-in seasonal unit costs on a dollar per MWh basis. The ratio of these overall
599 average seasonal costs to the overall total costs from Table No. 14 are the
600 seasonal payment ratios upon which seasonal payments to the winning bidders are
601 based

602 Q. **Please explain Table No. 16 of Resp. Exhibit 5.3.**

603 A. Table No. 16 contains a reconciliation of the revenues recovered by application of
604 the rate multipliers from Table No. 14 to the payment to suppliers based on the
605 seasonal payment factors from Table No. 15 and is used as a check of the Prism's
606 operation.

607 Q. **What is the next step in translating the single winning bid price from the**
608 **auction processes into BGS rates for the respective customer groups?**

609 A. The next step in the process is the determination of the Ameren Companies'
610 average capacity and energy supply cost. The average cost is the weighted
611 average price that would be paid to BGS suppliers accounting for seasonal
612 payment factors and BGS sales volume by season. As discussed in Mr.
613 Blessing's direct testimony, we are proposing, for the under 1MW (< 1,000 KW)
614 customers, that the auction tranches have a three year term with 1/3 of the
615 tranches expiring and being re-auctioned annually. The initial auction will have a
616 17-month, a 29-month, and a 41-month product. There will be a one year product
617 for the large customer class BGS-4, except in the initial auction for which there
618 will be a 17month product. Each year the auctions will be repeated so that the
619 Companies can replace the expiring tranches from prior auctions. The clearing
620 price for each of the three products (the current auction results with prior auction
621 results) will be multiplied by the Companies' seasonal payment factors (those
622 from current auction and those from prior auctions). These seasonal prices for
623 each product will then be weighted by the associated number of tranches and
624 seasonal sales volumes to determine the weighted average cost applicable to BGS
625 load.

626 For example, assume that for the initial auction for the under 1MW customers: (1)
627 the winning bid prices for the 17, 29 and 41-month products are \$40.00, \$41.00
628 and \$42.00 per MWh, respectively; (2) there are 60 total tranches bid, 20 tranches
629 per product; (3) the seasonal payment factors per the initial Prism are 1.200 and

630 0.900 for the summer and non-summer respectively; (4) forecast BGS class MWh
631 at the bulk system are 9,000,000 for the summer period and 14,000,000 for the
632 non-summer period. The resulting weighted average bid price would be

$$\$40 \times 20/60 \times 1.2 \times 9,000,000 = \$144,000,000$$

$$\$41 \times 20/60 \times 1.2 \times 9,000,000 = \$147,600,000$$

$$\$42 \times 20/60 \times 1.2 \times 9,000,000 = \underline{\$151,200,000}$$

\$442,800,000

$$\$40 \times 20/60 \times 0.9 \times 14,000,000 = \$168,000,000$$

$$\$41 \times 20/60 \times 0.9 \times 14,000,000 = \$172,200,000$$

$$\$42 \times 20/60 \times 0.9 \times 14,000,000 = \underline{\$176,400,000}$$

\$516,600,000

\$959,400,000

$$\$959,400,000 \div 9,000,000 + 14,000,000 = \underline{\$41.71} \text{ per MWh}$$

633 Continuing on, the following auction for the next BGS rate period will be 30
634 tranches for a 36-month product, at a winning bid price of \$45.00 per MWh. The
635 previous 17-month product is finished and there are 12 and 24 months remaining
636 on the previous auction's 29 and 41-month products respectively. Assume: (1)
637 the seasonal payment factors for the second auction per the Prism are 1.150 and
638 0.8750 for the summer and non-summer respectively and (2) BGS class MWh at
639 the bulk system are 10,000,000 for the summer period and 15,000,000 for the
640 non-summer period. The resulting weighted average bid price for the next BGS
641 rate period would be:

$$\$41 \times 20/60 \times 1.20 \times 10,000,000 = \$164,000,000$$

$$\$42 \times 20/60 \times 1.20 \times 10,000,000 = \$168,000,000$$

$$\$45 \times 20/60 \times 1.15 \times 10,000,000 = \underline{\$172,500,000}$$

\$504,500,000

$$\$41 \times 20/60 \times 0.900 \times 15,000,000 = \$184,500,000$$

$$\$42 \times 20/60 \times 0.900 \times 15,000,000 = \$189,000,000$$

$$\$45 \times 20/60 \times 0.875 \times 15,000,000 = \underline{\$196,875,000}$$

\$570,375,000

\$1,074,875,000

642 The new weighted average bid price that would be applicable to the next BGS rate
643 period would then be:

$$\$1,074,875,000 \div 10,000,000 + 15,000,000 = \underline{\$43.00} \text{ per MWh.}$$

644 This process would continue annually as the 12-month product would terminate
645 and a new 36-month product would be auctioned.

646 The final step in the process is converting this resulting annual weighted average
647 price into retail BGS rate values for the BGS rate period. This is accomplished by
648 multiplying the weighted average bid price by the applicable rate multiplicative
649 factors as determined by the Prism in Table No. 14.

650 For illustrative purposes, I have attached as Resp. Exhibit 5.5 a schematic
651 or pictorial of the Prism, showing the inputs and other factors as described that
652 result in the final price.

653 **Q. Do the Ameren Companies envision the outputs of the Prism being used for**
654 **other than rate development?**

655 A. Yes. The BGS pricing spreadsheets are also intended to provide bidders with an
656 easy to use tool that can translate auction prices for each term into retail BGS
657 rates. Bidders can enter into the spreadsheet auction prices for the Companies' 3-

658 year and 1-year tranches, click on a calculate box and be able to view the BGS
659 rates that would result if the auction were to clear at the entered price levels. BGS
660 prices may be important to bidders for the purpose of assessing the likelihood and
661 degree of migration to and from BGS rates.

662 It is contemplated that bidders may use these spreadsheets in two ways. First, in
663 preparation for the auction, bidders can examine a wide variety of scenarios of
664 potential auction clearing prices and analyze the retail rates that result from those
665 scenarios. These analyses can be used to examine how potential migration from a
666 given set of retail rates may affect the bidder's valuation of the auction
667 opportunity. Second, as the auction is in progress, bidders will be able to enter
668 going prices and update their analysis of potential migration and the auction
669 opportunity. Also, as discussed above, Table No. 15 provides bidders with the
670 seasonal factors for payments to bidders.

671 **Q. Should one expect that billings generated under rates from the above-**
672 **referenced prism achieve Ameren's goal of precisely recovering all costs**
673 **associated with the procurement of said fixed power?**

674 A. No. The decomposition of the single winning auction prices across several rate
675 class and pricing periods based on predicted load characteristics and estimated
676 losses, along with seasonal payment factors for remittance of payments to
677 successful bidders, will result in under or over-collection of power costs. As a
678 result, the proposed BGS Riders "point to" the previously mentioned Market
679 Value Rider -Rider MV (Resp. Ex. 4.1).

680 Q. **Please explain.**

681 A. As discussed in Mr. Mill's direct testimony, Rider MV contains, among other
682 items, the process for translating winning bid prices into BGS rates and an
683 MVAF, which is an adjustment mechanism to synchronize BGS power supply
684 costs to billed revenue. Mr. Mill provides additional detail on the rationale and
685 the mechanics of the MVAF.

686 IV. **RIDER RTP – REAL TIME PRICING DISCUSSION**

687 Q. **Mr. Cooper, please discuss Ameren's proposed RTP offering to customers
688 with individual demands of greater than 1,000 kilowatts.**

689 A. The proposed Rider RTP-L contains provisions for the availability of RTP to all
690 customers with individual demands equal to or greater than 1,000 kilowatts (>
691 1MW). Additionally, we have designated RTP as the default power service for
692 customers who either: (1) do not opt for BGS or RES service during the open
693 enrollment period described in the testimony of Mr. Blessing or (2) lose RES
694 supply for any reason.

695 Q. **Please discuss the pricing of power under Rider RTP-L.**

696 A. All energy purchased under Rider RTP-L will be priced based on provisions of
697 the RTP-L bid contracts. These contracts contain three components for RTP-L
698 service: (1) Energy at MISO Locational Marginal Hourly Prices ("LMPs") that
699 vary by Ameren control area designation; (2) an energy based Rider D - Default
700 Service Supply Availability Charge; and (3) a capacity based hourly demand
701 charge. The proposed Rider MV contains the provisions for the pricing of these
702 components. Of course, all of these charges will be adjusted for system losses.

703 **Q. Earlier you mentioned Ameren's desire to have one set of prices for power**
704 **and energy across its entire Footprint. Why are you proposing varying RTP**
705 **related LMPs depending on which control area of Ameren's a customer is**
706 **located?**

707 A. Current MISO provisions do not allow the Ameren control areas to be treated as
708 one "virtual" control area for LMP purposes. As a result, it is not possible to
709 provide a single LMP for any hour that would be representative of the comparable
710 hour LMP for each of Ameren's three control areas. Therefore, RTP customers
711 will be subject to LMPs based on the control area of which they are located.
712 Differences in LMPs among the Ameren control areas are primarily tied to
713 transmission congestion costs and are expected to be minimal. Additionally, we
714 are optimistic that in time MISO will treat the control areas as one and subsequent
715 RTP related LMPs would be same for all of the Ameren Companies.

716 **Q. Are any of the above mentioned charges for Rider RTP-L customers**
717 **applicable to Rider RTP-L eligible customers with RES service?**

718 A. Yes. Pursuant to the RTP-L bid contracts, the Companies are proposing that all
719 Rider RTP-L eligible customers with RES service be subject to the non-
720 bypassable Rider D.

721 **Q. Please explain.**

722 A. RTP-L power and supply bidders have included a Rider D charge or component
723 on a cents per kilowatt hour basis for all Rider-RTP-L load and all Rider RTP-L
724 eligible load with RES service. As stated earlier, we propose to bill this charge on

725 a cents per kilowatt hour basis, as adjusted for losses, to all Rider RTP-L
726 customers and Rider RTP-L eligible customers with RES power service.

727 **Q. Please discuss the proposed RTP offering to customers with individual**
728 **demands of less than 1,000 kilowatts (< 1 MW).**

729 A. The proposed Rider RTP contains provisions for the availability of RTP to all
730 customers with individual demands of less than 1,000 kilowatts. Unlike terms for
731 customers with individual demands of 1,000 kilowatts or greater, the Companies
732 have designated BGS the default power service for customers with individual
733 demands of less than 1,000 kilowatts.

734 **Q. Please discuss the pricing of power under Rider RTP.**

735 A. All energy purchased under Rider RTP will be priced under Rider MV.
736 Essentially, small customers opting for this service will receive "virtual" or
737 equivalent billing under proposed Rider RTP-L, as described above, excluding the
738 Rider D charge.

739 **Q. Please elaborate.**

740 A. As discussed in the testimony of Mr. Blessing, the Companies will not request
741 bids for RTP power for customers with individual demands of less than 1,000
742 kilowatts. However, the Companies propose that these customers be billed as if
743 they were served under Rider RTP-L without the imposition of Rider D charges
744 for customers within this category who do opt for RES service. Therefore, Rider
745 D charges will only be applicable to customers opting for RTP service. The
746 rationale for omitting Rider D charges for RES-served customers in this category
747 lies in the defaulting of these customers to BGS versus RTP. The bid price for

748 BGS for all customers in this class should include a component for the defaulting
749 of this service to BGS; the inclusion of Rider D on RES served load in this
750 category would suggest a “double counting” of sorts.

751 V. **SWITCHING RULES DISCUSSION**

752 Q. **Will customers eligible for the various BGS service offerings be subject to**
753 **switching rules?**

754 A. Yes. There is a direct correlation between auction bid price and switching and
755 minimum stay requirements for customers with choices between utility provided
756 power and service from a RES. Typically, the greater the load uncertainty, the
757 greater the probability that suppliers will be compelled to add larger risk
758 premiums to offset risks. However, there are concerns that the existence of
759 switching and minimum stay rules may impede the development of the power
760 market. The following switching/minimum stay rules should strike a reasonable
761 balance between the goals of supporting the development of a robust power
762 market and, at the same time, obtaining the lowest possible market prices for
763 customers. The proposed Rider MV tariffs contain the applicable switching rules.

764 VI. **TRANSMISSION SERVICE DISCUSSION**

765 Q. **You have now discussed the proposed post-2006 power service offerings.**
766 **Please discuss the Companies’ plan for Transmission Service offerings.**

767 A. The Companies plan to file a Transmission Service Rider – Rider TS with their
768 next Delivery Service case. This rider will contain all provisions for the
769 providing of transmission service to customers opting for power service from the
770 Companies’ post-2006 and will provide for full recovery of all costs, fees, and

771 charges for transmission and related services not otherwise recovered under the
772 BGS or RTP riders. This rider is not expected to apply to customers taking
773 service from a RES.

774 **VII. OTHER POWER SUPPLY DISCUSSION**

775 **Q. What are you proposing for power sales to customers with non-emergency**
776 **self-generation that operates in parallel with the Ameren Companies?**

777 A. We are proposing that customers with self-generation capacity of less than five
778 (5) megawatts be offered power service under either Rider BGS or Rider RTP.
779 This proposal provides customers with small to medium sized self generation
780 units the flexibility of selecting applicable BGS or RTP power service
781 simultaneous with full flexibility in operating their generators in a manner
782 consistent with their internal economics. Based on initial customer survey
783 intelligence, it is anticipated that the aggregate capacity of self generation in this
784 category represents approximately five (5) percent of total non-emergency
785 customer self generation installed on the Ameren Companies.

786 **Q. What are you proposing for power sales to customers with non-emergency**
787 **self-generation equal to or greater than five (5) megawatts that operates in**
788 **parallel with the Ameren Companies?**

789 A. We are proposing that customers with self-generation capacity equal to or greater
790 than five (5) megawatts be offered a “hybrid” of power service under Rider BGS
791 and Rider RTP or, in the alternative RTP, only.

792 Q. **Please explain the proposed hybrid Rider BGS and Rider RTP power**
793 **offering for these customers.**

794 A. Customers with non-emergency self-generation at these levels tend to be very
795 sophisticated energy managers. In some cases, these customers utilize excess
796 steam from product process operations to run in house generator sets. We are
797 proposing that customers in this category be subject to a hybrid billing that: 1)
798 adequately reflects the costs of providing power service to their unique
799 operations, 2) provides proper price incentives with regard to whether self
800 installed generation output is more economic than market based RTP, and 3)
801 minimizes the opportunity for these customers to place low load factor load on the
802 system at prices that don't reflect actual market prices.

803 Q. **Please elaborate.**

804 A. First, customers in the above category will be required to pay the Ameren
805 Companies for the installation of metering or install, at their own costs, acceptable
806 metering for measuring the output of their generators. Additionally, standard
807 metering for the billing of the Companies' DS, BGS, and RTP services will be
808 required. The hybrid proposal will bill all Company metered power usage in
809 excess of that that could be hypothetically served by the customer's self
810 generation at a one-hundred percent capacity factor under the applicable Rider
811 BGS fixed price product. However, any Company metered power usage metered
812 during intervals where the customer's generator is operating at less than one-
813 percent capacity, will be billed under the applicable RTP. While this approach is
814 somewhat complex, billing can be easily accomplished by a comparison of the

815 interval meter reads between the customer's generation meter and the customer's
816 DS, BGS, and RTP power meter. Additionally, this hybrid billing addresses the
817 three concerns mentioned above and is just and reasonable. Based on initial
818 customer survey intelligence, it is anticipated that the aggregate capacity of self
819 generation in this category represents approximately ninety-five percent of total
820 non-emergency customer self generation installed on the Ameren Companies'
821 system. Additionally, this hybrid billing proposal provides a proper balance
822 between the customer's desire to economically operate self generation and our
823 desire to have power prices that reflect cost causation and equitable cost recovery
824 principles.

825 **Q. What are you proposing for power and energy sales to customers desiring**
826 **power service from the Ameren Companies to supplement or augment power**
827 **being provided by an ARES?**

828 A. We are proposing that customers desiring power and energy from Ameren to
829 supplement or augment power provided from an ARES be served under the
830 applicable RTP offering. The application of the RTP offering for supplementing
831 or augmenting power and energy provided by a ARES is reasonable considering a
832 primary criterion (i.e., homogeneous load or usage characteristics) in establishing
833 rate design for the Company's fixed price offering. A customer obtaining power
834 and energy service from a RES may be homogeneous with the other ARES or
835 Company customers from a load perspective, however, its use of power and
836 energy service from an ARES versus that served by one of the Companies could
837 vary significantly. For example, if we were to offer the fixed price product to

838 these participants in the market, one would expect that, wherever possible, they
839 will place load swings or peaks during periods of high costs on our system at a
840 fixed price, while base loading on the ARES at a lower per unit price. The use of
841 RTP for power and energy service required to supplement or augment ARES
842 service minimizes the likelihood of these customers behaving in this manner,
843 prevents subsidies to the detriment of our fixed price customer groups, and sends
844 a better or more proper price signal. Thus, the use of RTP for this service is just
845 and reasonable, and also promotes the development of an efficient market for
846 power and energy.

847 **Q. Earlier you mentioned that the Ameren Companies would be filing DS cases**
848 **for new rates to become effective prior to the effective date of the post-2006**
849 **BGS offerings. Please discuss the basic objectives of your delivery services**
850 **filings as they may relate to BGS.**

851 A. The objectives of the DS filings are as follows: (1) complete recovery of the
852 Ameren Companies' DS related revenue requirements; (2) alignment of DS
853 classes with BGS/RTP classes; (3) class revenue requirements and rate design that
854 reflect cost causation and equitable cost recovery principles; (4) competitively
855 neutral DS rates (i.e., rates for DS should be the same whether customer opts for
856 virtual bundled service from the Ameren Companies, or takes DS from the
857 Companies with power from an ARES. Achievement of these DS objectives will
858 assist in promoting a robust retail market for power in Illinois, promote ease of
859 customer and employee understanding of our rates and tariffs, and provide our
860 shareholders with a reasonable rate of return. As a result, all stakeholders benefit.

861 Q. **Have you prepared an exhibit that maps the Ameren Companies' existing**
862 **bundled retail electric Service Classifications to expected post-2006 DS, TS,**
863 **and BGS/RTP applications for the continuation of "virtual" bundled service?**

864 A. Yes. Resp. Exhibit 5.4 contains this mapping for the Ameren Companies'
865 classifications.

866 Q. **Will customers defaulted to BGS-1, 2, and 3 on January 2, 2007, be required**
867 **to remain on such for an entire year?**

868 A. No, we recognize that despite the efforts of all the parties in this process to
869 educate consumers prior to January 2, 2007, there will still be some confusion,
870 especially with smaller customers. As a result, all customers initially defaulted to
871 BGS 1, 2, or 3 may switch to any other available BGS rates at any time subject
872 only to DASR requirements.

873 Q. **Please discuss your proposed BGS treatment for new connections/customers**
874 **post-2006.**

875 A. All "new" (i.e., customers served from new distribution extensions or successor
876 customers) customers will be given the option of either BGS "fixed" price or RTP
877 service, if they request power service from the Ameren Companies.

878 Q. **Does this conclude your direct testimony?**

879 A. Yes, it does.