STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO Proposed general increase in electric delivery and gas delivery service rates. Central Illinois Public Service Company d/b/a AmerenCIPS Proposed general increase in electric delivery and gas delivery service rates. Illinois Power Company d/b/a AmerenIP Proposed general increase in electric delivery and gas delivery service rates.	)))))))))))))))))	Docket Nos. 09-0306 – 09-0311 (Consolidated)

REPLY BRIEF OF THE STAFF
OF THE ILLINOIS COMMERCE COMMISSION

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Staff of the Illinois Commerce Commission ("Staff"), by and through its undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's ("Commission" or "ICC") Rules of Practice (83 Ill. Adm. Code 200.800), respectfully submits its Reply Brief in the instant proceeding.

I. INTRODUCTION

A. Overview

In this proceeding, the Commission is investigating the June 5, 2009 requests for general increases in gas and electric delivery services rates pursuant to Article IX of the

Illinois Public Utilities Act (the "Act"), 220 ILCS 5/9, filed by the Ameren Illinois Utilities, Central Illinois Light Company d/b/a AmerenCILCO ("CILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS ("CIPS"), and Illinois Power Company d/b/a AmerenIP ("IP") (collectively, "Ameren," the "Company," the "Companies," "AIU" or the "AIUs").

B. Procedural History

Initial Briefs ("IB") were filed on January 14, 2010, by the Cities of Champaign, Urbana, Decatur, Bloomington and the Town of Normal, Illinois (the "Cities"); the Kroger Co. ("Kroger"); Constellation NewEnergy – Gas Division, LLC ("CNE-Gas"); the Illinois Industrial Energy Consumers ("IIEC"); AARP; System Council U-05 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW"); Grain & Feed Association of Illinois ("GFAI"); the People of the State of Illinois and the Citizens Utility Board ("AG/CUB"); Staff; and Ameren. Staff's Initial Brief identified and responded to many if not most of the arguments raised in the Companies' Initial Brief. In this Reply Brief, Staff has incorporated many of those responses by reference or citation to Staff's Initial Brief. However, in the interest of brevity, Staff has not raised and repeated every argument and response previously addressed in Staff's Initial Brief. Thus, the omission of a response to an argument that Staff previously addressed simply means that Staff stands on the position taken in Staff's Initial Brief because further or additional comment is neither needed nor warranted. As explained in detail below and in Staff's Initial Brief, the arguments raised by Ameren lack merit and must be rejected.

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1. Pro Forma Plant Additions (2009-2010)

2. Accumulated Reserve for Depreciation

AIU argue at length that the decision in this proceeding must follow the decisions made in prior rate cases associated with this adjustment proposed by both AG/CUB and IIEC. In the current cases, AIU have included all distribution projects, including blanket projects estimated to be in service 14 months beyond the test year. This, in effect, moves the gross plant in service balance forward 14 months. Thus, the AIU is guilty of exactly the same tactic that it accuses the intervenors of, that is, moving one element of rate base to a future period while other elements of the revenue requirement remain based on an historical period. (Ameren IB, p. 21) Both components of the net plant must be adjusted if either of the components is to be adjusted to comprehensively reflect overall plant investment.

The AIU claim that the distinguishing factor in the Order in Docket Nos. 02-0798/03-0008/0009 (Cons.) is that the CIPs' net plant in service was declining or static. (Ameren IB, p. 25) They conveniently omit the conclusion, as it relates to AmerenUE, in that case where net plant was not declining. The IIEC correctly call attention to that difference in its Initial Brief when it discusses the treatment afforded AmerenUE to limit its post test year capital additions to the extent that they exceed increased accumulated depreciation. (IIEC IB, p. 21) Thus, even though it is undisputed that the AIU's net plant in service has been increasing (Ameren IB, p. 25), the Commission has stated it "might be inclined to allow post test year additions to rate base" but only to the extent that those additions exceed increases to accumulated depreciation. (IIEC IB, p. 21)

3. Plant Additions (2007-2008): Pana East Substation

Staff's position is that AmerenCIPS should not allocate 100% of its $2 million cost for relocating Pana East Substation to only its electric ratepayers, whereas Ameren believes this allocation is appropriate. (Ameren IB, pp. 26-27)

Ameren claimed that Staff did not adequately explain why a portion of the relocation costs should be allocated to AmerenCIPS' other lines of business in addition to electric distribution. (*Id.*, p. 27) Ameren's claim is simply not true. Staff witness Rockrohr explained that the former substation site was contaminated with coal tar from a nearby manufactured gas plant that CIPS owned and operated, and that the substation relocation occurred to facilitate that contamination clean-up. Mr. Rockrohr explained that AmerenCIPS' relocation of Pana East Substation was not initiated or required because the former substation was inadequate. (Staff IB, p. 12) This fact was corroborated by both Ameren and IBEW. (Ameren IB, p. 26; IBEW IB, p. 4) Mr. Rockrohr explained that Section 58.9 of the Environmental Protection Act assigns liability for the cost of the clean-up of contamination to the party or entity that caused the release, not to the party or entity that owns the contaminated property. (Staff IB, p.13) The manufactured gas plant was never owned or operated solely by AmerenCIPS' electric ratepayers. Mr. Rockrohr further explained that if a 3rd party were to request that AmerenCIPS relocate its adequate facilities, AmerenCIPS would appropriately charge the 3rd party for the cost of those facilities, even though the relocated facilities, after work was completed, would be used and useful in providing electric service to customers. (*Id.*, pp. 14-15) Despite Ameren's claim to the contrary, Staff did thoroughly explain its position.

Ameren also stated "Staff's position ultimately boils down to the notion that it might be appropriate to allocate some percentage of relocation costs to electric distribution customers, but not 100% of the costs; therefore, since the AIUs have proposed to allocate 100% of the costs, none of the costs should be recovered." (Ameren IB, p. 30) Ameren's characterization of Staff's position is not complete. Ameren certainly is correct that Staff holds the position that electric ratepayers should not bear 100% of the substation relocation costs. However, Staff would not have objected to recovery using a reasonable cost allocation for the project. (Staff Ex. 24.0R, p. 4)

Ameren criticized Staff for not proposing an alternative allocation, claiming that Staff "refused to do so." (Ameren IB, p. 28) Staff is not aware that Ameren ever requested Staff to provide an alternative allocation; Staff found no record of such a request in Ameren's testimony or data requests. Neither did Staff recall or locate any refusal by Staff to provide an alternative allocation. Furthermore, Staff had the understanding that this was AmerenCIPS' electric rate case, and AmerenCIPS should be able to justify its own additions to electric distribution plant. Ameren's accusation that Staff refused to propose an alternative allocation is both troubling and disingenuous. It appears that, rather than justifying AmerenCIPS' proposed 100% allocation of relocation costs to electric ratepayers, which Staff requested it do, Ameren elected to wait until the evidentiary hearing, where it attempted to shift to Staff the burden to establish an appropriate cost allocation for the purposes of AmerenCIPS' rate recovery. (Tr., pp. 209 - 210, December 14, 2009) In direct testimony, Staff witness Rockrohr clearly stated that he would consider modifying his recommendation if Ameren provided information or evidence to fully explain and justify its proposed 100% allocation. (Staff Ex. 11.0R, p. 10) Rather than providing necessary information to support its own proposal, or proposing an alternative allocation, Ameren simply accused Staff of not suggesting an alternative cost allocation.[1]

Ameren and Staff agreed that relocation of Pana East Substation was initiated to facilitate clean-up of coal tar beneath the former substation site, and agreed that the relocation likely allowed AmerenCIPS to remediate the coal tar contamination in the

[1] Actually, Mr. Rockrohr suggested that 100% allocation of costs to AmerenCIPS' shareholders would be preferable to 100% allocation to AmerenCIPS' electric ratepayers, so Ameren's claim that Staff refused to suggest an alternative allocation is not only disingenuous, but also untrue. (Staff Ex. 24.0R, pp. 5-6; Ameren Ex. 50.2, Staff response to Ameren data request AIU-ICC 29.04)

most cost-effective manner. (Ameren IB, p. 26) In other words, had AmerenCIPS not relocated the substation to facilitate clean-up, the actual clean-up costs that AmerenCIPS would have incurred and recovered through Riders EEA and GEA would have been higher. (Ameren Ex. 50.0 (Revised), p. 7)

It is also undisputed that AmerenCIPS had to clean up the contamination because its nearby manufactured gas plant caused the contamination, not because it owned the contaminated property, and that the substation relocation costs did not cover any of the actual coal tar clean-up; the clean-up was a different project. AmerenCIPS' costs for the coal tar clean-up, recovered from both gas and electric ratepayers through Riders EEA and GEA, were minimized as a result of the relocation. In other words, AmerenCIPS relocated the substation in order to provide cost savings for both gas and electric ratepayers, and then AmerenCIPS proposed to recover all costs for the relocation from only electric ratepayers.

Near the end of its Initial Brief, Ameren stated, "The question unanswered by Staff is, if allocation of 100% of the costs to electric ratepayers is not appropriate, then what is?" (Ameren IB, p. 30) If the Commission determines that AmerenCIPS should recover its costs for relocating Pana East Substation, but agrees with Staff that 100% allocation of costs to electric ratepayers is not appropriate, the Commission may wish to consider an allocation that closely matches the allocation of the clean-up costs recovered through AmerenCIPS' environmental riders (Rider EEA and Rider GEA).

In its Initial Brief, IBEW disagreed with Staff's position regarding cost allocation for AmerenCIPS' Pana East Substation, substantially echoing Ameren's arguments that the relocation was necessary and associated costs should be recoverable through rates. Staff relies upon its discussion above to reply to the issues raised in IBEW's Initial Brief, with the following exception. A concern raised in IBEW's Initial Brief that was not also expressed in Ameren's relates to possible job losses should the Commission determine not to allow AmerenCIPS to recover the discussed relocation costs. IBEW expressed concern that if Ameren fails to recover its relocation costs, it might reduce spending in other areas, such as operations and maintenance. (IBEW IB, p. 5)

Though Staff does not think it would be a good idea to do so, Ameren could decide to reduce its maintenance and operations expenditures for any number of reasons, independent of the Commission's decision regarding this substation relocation issue. While potential job loss might be a legitimate concern, Staff does not believe the Commission should base its decision upon this concern.

4. Hillsboro Storage Field – Used and Useful

AIU argues that there are four reasons that Staff's recommended used and useful disallowance is flawed and should be rejected. Specifically, AIU claims that: (1) Staff incorrectly relies on the 1993 design capacity estimate for Hillsboro; (2) Staff concedes that Hillsboro storage field should cycle 6.4 Bcf for the next several years; (3) Staff overlooks the fact that Hillsboro substantially benefits customers; and (4) Staff wrongly connects its used and useful adjustment to past operational concerns at Hillsboro. (Ameren IB, p. 32) Staff disputes each of these arguments.

In addition, AIU claims that the Commission should not accept Staff's proposal because Staff's proposal of the storage field's used and usefulness is so near 100%. (*Id.*) Staff also addresses this topic below.

Staff's used and useful calculation incorrectly relies on the 1993 design capacity of Hillsboro

AIU attempts to place reliance on prior Commission Orders to dispute Staff's proposed used and useful adjustment. However, AIU fails to demonstrate how these Orders relate to the instant proceeding; instead, AIU's arguments are an inappropriate subordination of the Commission's Orders. Further, AIU claims that prior instances where utilities have altered the working inventories of their storage fields, without a used and useful adjustment, support its claim that no adjustment is necessary in the instant proceeding. Staff disagrees.

First, AIU indicates that the Commission, in Docket No. 89-0276, had previously rejected reliance on design capacity in determining used and usefulness and noted that the Commission stated "….it was not possible to determine precisely what the net output of the plant would be during its design and construction stages, until it was completed, placed in service and tested." (Order, Docket No. 89-0276, June 6, 1990, p. 74; Ameren IB, pp. 32-33) However, AIU is incorrect in its application of this Order to this proceeding. The Commission's discussion within the Order determined the appropriate in-service capacity rating to assign the Clinton power plant in order to determine the appropriate percentage of the plant to place into rates.

AIU placed the Hillsboro storage field in-service on August 31, 1993. (Order, Docket No. 93-0183, April 6, 1994, p. 8) In that same proceeding, AIU requested and the Commission approved its request to place the costs of the Hillsboro expansion fully into rates and received a determination that the expansion was used and useful. (*Id*.) Further, during the first winter of operation, 1993-1994, the Hillsboro storage field operated at its expected levels, or in other words, AIU tested the capability of the field.

(Staff Ex. 12.0, p. 25, Table 1) Therefore, AIU achieved the original operating specifications, peak day of 125,000 Mcf/day and seasonal capacity of 7.6 Bcf, for the Hillsboro storage field. As such, the Commission's Order in Docket No. 89-0276 does not require any deviation from the values Staff assigned to Hillsboro in its used and useful calculation for the Hillsboro storage field in the instant proceeding.

Second, AIU referenced the Commission Order from Docket Nos. 87-0427, et al. AIU indicated that this Order noted that where capacity is restricted or not available due to physical constraint, such capacity should not be included in a plant's total effective capacity for purposes of determining used and usefulness. (Ameren IB, p. 33) AIU also had a second reference to Docket Nos. 87-0427 et al., namely, that the Commission had indicated that the "used and useful calculation should be based on the Company's existing capacity configuration." (*Id*., pp. 34-35) AIU then concluded that it was not appropriate for Staff to base its used and useful calculation on design, as opposed to actual capacity, and instead claimed that the Commission's used and useful assessment should consider the current effective capacity of Hillsboro. (*Id*.)

However, AIU is once again distorting the Commission's rulings. The Commission's Order in Docket Nos. 87-0427 et al. discussed effective capacity and capacity configuration, but these discussions were in reference to the Commission's determination of whether to include the capacity from retired electrical peaking units or capacity associated with summer limitations on Commonwealth Edison's power production plants in the used and useful calculation. (Revised Order on Remand, Docket Nos. 87-0427, et al., February 24, 1993, p. 44) The Commission's discussion is significant because the used and useful determination of an electric power production plant, once it is placed into service, compares the utility's peak demand, adds a reserve margin, subtracts out total capacity without the plant in question, and then reviews what percentage of the plant is needed to meet customers' demands. (*Id.*, Appendix B) However, there is no corresponding topic in the instant proceeding. As noted above, AIU placed the Hillsboro storage field in-service in 1993, which is the point in time for Staff and the Commission to review what other resources AIU had in place to determine if AIU needed the Hillsboro storage field and if it was used and useful. As such, the issues in the instant proceeding, namely AIU's inability to operate the Hillsboro storage field at its full capacity, are distinguishable from AIU's reference to Docket Nos. 87-0427 et al.

Further, as Staff noted in its Initial Brief at page 16, the Commission has previously ruled regarding the manner to consider the used and usefulness of a storage field already placed in-service in Docket No. 04-0476. That proceeding set forth and provided the only Commission guidance regarding a used and useful review of an in-service gas storage field. AIU has failed to show why the Commission should deviate from its past practice. Therefore, AIU's attempted distortion of prior Commission's used and useful determinations is illogical and inappropriate and should be rejected.

AIU also claims that the fact that other companies have adjusted working volumes within their storage fields in the past without penalty is significant. Specifically, AIU points to Docket No. 90-0127 and Docket Nos. 07-0585 – 07-0590 (Cons.) as support for its statement that an adjustment to the inventory in a storage field does not necessarily lead to a used and useful adjustment. (Ameren IB, p. 35) Staff does not dispute this assertion. AIU then claimed that the instant proceeding is the same as these earlier cases because studies indicate the need to adjust working and base gas. (*Id.*) Staff disagrees with this assertion. As Staff noted in its Initial Brief at pages 22-24, AIU is not proposing to alter Hillsboro's working or base gas inventory levels and has chosen to operate the storage field in a consistent manner to determine the operating parameters of the storage field. These facts distinguish the instant proceeding from those referenced by AIU.

<u>Staff concedes that Hillsboro storage field should cycle 6.4 Bcf for the next several years</u>

AIU noted that Staff did not disagree with its reasoning for operating the Hillsboro storage field at the 6.4 Bcf level and that Staff agreed that operating at a consistent manner will allow AIU to better determine the operating characteristics of the field. (Ameren IB, p. 36) Staff does not dispute these statements. However, AIU then claimed that Staff acknowledges that Hillsboro may not be able to operate at its design capacity and as such, AIU claims that it should not be penalized for operating the Hillsboro storage field in a prudent manner. (*Id.*, p. 37) Staff's disagrees with this assertion. However, Staff's Initial Brief at pages 22-24, already provides a full discussion regarding why it agrees with AIU's logic for operating the Hillsboro storage field in a consistent manner at the 6.4 Bcf level, but then provides details regarding the implications and reasoning behind AIU's request. These discussions explain why Staff disputes AIU's assertion that Staff acknowledges that Hillsboro may not be able to operate at its design capacity and why Staff concludes a used and useful disallowance is still needed. As such, that discussion need not be repeated here.

<u>Staff overlooks the fact that Hillsboro substantially benefits customers</u>

AIU claims that Hillsboro is necessary to meet customer demand and it is economically beneficial in meeting such demand and as such, it should be considered used and useful. (Ameren IB, p. 38) Staff does not dispute that Hillsboro is needed to meet customer demand or that it provides economic benefits, but disputes that these facts should alter Staff's used and useful determination.

The economic benefits that Hillsboro provides ratepayers are ingrained within its used and useful calculation. Specifically, Staff's used and useful calculation relies on the weighting of the benefits between the peak day and seasonal capacity savings to calculate the appropriate used and useful amount. (Staff Ex. 12.0, pp. 27-31) This is the same methodology and reasoning that Staff recommended and the Commission accepted in Docket No. 04-0476. (*Id.*, p. 32)

Staff's used and useful adjustment recognizes that AIU designed the Hillsboro storage field to operate at a certain capacity and that the Commission approved the Hillsboro storage field to operate at that higher capacity, which means the Hillsboro storage field would provide even more savings to customers if AIU operated the field at its expected levels. (Staff Ex. 25.0, p. 21) Further, AIU made this exact same argument in Docket No. 04-0476. (Order, Docket No. 04-0476, May 15, 2005, p. 34) However, the Commission in Docket No. 04-0476 rejected AIU's reasoning and agreed with Staff that a used and useful adjustment was appropriate. Therefore, while Staff agrees that the Hillsboro storage field meets customer demands and provides benefits, it does not absolve AIU from operating the Hillsboro storage field in a less than 100% used and useful manner.

<u>Staff wrongly connects its used and useful adjustment to past operational concerns at Hillsboro</u>

AIU claims that Staff has improperly linked its used and useful analysis to past

Hillsboro concerns. Specifically, AIU notes that the facts from the prior case where the Hillsboro storage field's used and usefulness was at issue are distinguishable from the facts in the instant proceeding and that AIU could only now identify the geologic limitations to the field's technology. (Ameren IB, p. 38) AIU also claimed that Staff considered volume histories in Docket No. 04-0476, but in the instant proceeding Staff is relying on scheduled withdrawal volumes. (*Id.*, pp. 38-39) Staff addresses each topic below.

Staff agreed that some of the facts have changed between the instant proceeding and Docket No. 04-0476, in part, because five years separate those cases. However, Staff noted that the main issue that forms the basis for the used and useful adjustment remained the same, namely, that the Hillsboro storage field is not operating in the same manner that it was when AIU expanded the field and placed the cost associated with the Hillsboro expansion into its base rates in Docket No. 93-0183. (Staff Ex. 25.0, p. 19)

Regarding AIU's claim that the technology only now exists to identify the problem, Staff would note that AIU did not make this claim regarding the technology until the filing of its surrebuttal testimony. Aside from that point, Staff notes that the problem AIU is referencing is the migration of gas into the Joachim layer of somewhat permeable caprock. However, Staff noted that AIU admits that this migration has occurred since it started storing gas in the Hillsboro storage field in 1972. Further, when AIU expanded the field in 1993, it likely exposed additional areas for gas to migrate. However, that initial expansion took place over 15 years ago and migration was on-going during this time period. So while Staff does not dispute that some migration is likely still taking place, AIU does not have a good handle on all of these facets of Hillsboro's operation at this time. Staff considers that this occurred, in part, due to the past problems AIU has had with metering errors causing inventory reductions at the field and has kept AIU from being able to properly review or operate the field in the past. (*Id.*, pp. 27-28)

AIU admitted the Hillsboro Study provided additional insight into the operation of the Hillsboro storage field, but it also identified additional areas to investigate that will allow more specifics about the reservoir to become known. In other words, 16 years after the expansion of the field, AIU still does not know why the Hillsboro storage field operates at its current levels or even if the original 7.6 Bcf rating is appropriate. This problem should not be borne by ratepayers. Instead, it is a function of prior problems that AIU failed to identify in a timely fashion whose impact is still being felt today. (*Id.*, p. 28) Staff considers it reasonable that while AIU attempts to determine the operating parameters of the Hillsboro storage field, the ratepayers should be kept whole by using the original specifications of the field, thereby necessitating a used and useful adjustment.

Finally, AIU claimed that Staff, in Docket No. 04-0476, relied on historical withdrawal volumes from the Hillsboro storage field, but in the instant proceeding is placing reliance on the scheduled withdrawal volumes. Staff disputes this claim. Staff has clearly based its used and useful calculation on the historical withdrawal volumes from the Hillsboro storage field in a manner consistent with the approach used in Docket No. 04-0476. (*Id.*, p. 18; Staff Ex. 12.0, Schedule 12.01)

<u>Staff's used and usefulness calculation is very near 100%</u>

AIU claims that recommending a used and useful disallowance when Staff's proposed amount, 96.01%, is so close to 100% is inappropriate, especially given that gas storage operations can be unpredictable. AIU also indicates that a used and useful disallowance is not appropriate since new information suggests that AIU may change its operations. (Ameren IB, pp. 39-40)

Staff notes that while it did request the Commission address the topic of whether an amount existed where a used or useful determination was no longer needed, there is currently no Commission proceeding that addresses this topic. (Staff Ex. 12.0, p. 32) Further, while AIU suggests it may change the operating characteristics of the Hillsboro storage field, the record clearly shows that it has not made that proposal at this time. As such, the record shows the Hillsboro storage field is not operating at its expected levels and while AIU attempts to determine what those levels are, it is not appropriate for AIU ratepayers to subsidize AIU's 15-year journey to determine how to operate the Hillsboro storage field.

5. Cash Working Capital

The AIU is misleading with the claim that they are remitting payment for pass-through taxes 3.81 days prior to the receipt of payment from their customers. (Ameren IB, p. 43) For the Gross Receipts Tax which AIU refer to, the utility's liability is based upon the gross receipts which were received from customers during the preceding calendar month. (35 ILCS 615/3) The 31.34 days revenue lag is simply a calculation for the average time for all revenues to be in the control of the utility. That does not mean that no revenues are available to pay pass through taxes until after day 31. To compare that number with the expense lead for pass through taxes which are all paid on a date certain for each type of tax is misleading.

The AIU also mislead the reader with the claim that under Staff's proposal, revenues are in hand immediately. (Ameren IB, p. 43) Pass through taxes do not represent a cost of service that the utility has provided and for which it must await recovery through revenues. Staff's position is based on the fact that pass-through taxes are not an investment on which the utility needs to earn a return through the rates it charges. The AIU agree that they simply act as a conduit for the funds to flow through. (Staff IB, pp. 26-27)

While the AIU state that the CWC analyses are based on actual receipt and payment dates (Ameren IB, p. 44), those dates are used to measure the average passage of time from the provision of service to the receipt of funds for that service in general. The lag days for revenues are not based on a specific date of receipt, but rather a calculation based on the passage of time of many receipts of customer's bills to determine an overall average. To compare a number of days with a specific point in time has no meaning because another point in time could just as easily be compared that would yield a different result.

The AIU opine that Staff is applying the service period inconsistently between revenues and expenses. (*Id.*, p. 45) Staff has explained the different treatment in testimony. (Staff IB, p. 27) The service period, as it relates to the expense lead calculation, is based upon the period of time over which the liability is incurred. Thus, for pass through taxes which accrue over a month or quarterly period, it is consistent with the AIU's own definition of expense lead to include the service period in the calculation for pass through taxes. In contrast, the service period for revenues is associated with the timing of the provisioning of service (Ameren Ex. 31.0, p. 7) by Ameren witness Heintz's own definition. Thus, since no service is provided by the utility related to pass through taxes, there can be no service lag associated with the revenues. (Staff IB, p. 27)

6. Working Capital Allowance for Gas In Storage

AIU only raised two arguments that Staff has not already addressed in its Initial Brief at pages 27-31. First, AIU suggests that Staff's proposal is not consistent with the Commission's prior Order. (Ameren IB, p. 50, footnote 5) Second, AIU suggests that a review of future prices for January 2011 shows that the 2008 prices were not outliers. (*Id.*, p. 51) Staff disagrees.

AIU noted that Staff's proposal to use 2009 prices is inconsistent with the Commission prior AIU rate case Order (Docket Nos. 07-0585 – 07-0590 (Cons.)) because the prior order approved the use of NYMEX forward pricing to determine prices in 2008, which was two years after the 2006 test year, whereas Staff's proposal in this case uses 2009 gas prices which are only one year after the 2008 test year. (*Id.*, p. 50, footnote 5) Staff does not dispute the timing AIU noted, but disputes AIU's argument that this timing makes Staff's proposal inconsistent with the Commission's prior Order. AIU, in the instant case and in its most recent rate case proceeding before the Commission, selected a historical test year. Commission rules limit changes to the test year data for historical test years to known and measureable changes. The Commission entered its Order in Docket Nos. 07-0585 – 07-0590 (Cons.) on September 24, 2008, which means the evidentiary phase of the proceeding occurred during 2008.

In the instant proceeding, the evidentiary phase took place in 2009. As such, Staff is making use of the most recent known and measurable data in the instant proceeding, which is consistent with the Commission's practice in Docket Nos. 07-0585 – 07-0590 (Cons.). As such, Staff disputes AIU's claim that its proposal is not consistent with the Commission's prior AIU rate case order in Docket Nos. 07-0585 – 07-0590 (Cons.).

AIU also notes that a review of NYMEX closing prices for the January 2011 contract for the period 1/3/08 through 11/25/09 shows a large variance and then AIU claims that the average of that month's price shows AIU's 2008 gas prices are not outliers. (*Id.*, p. 51) However, AIU is comparing a single month's price, January, to the average price over the year, which is not a valid comparison. Further, Staff's analysis provided a review that showed a recent (11/2/09) review of NYMEX future prices for 2010 and 2011, the time period when AIU's rates go into effect, that the gas prices Staff used in its calculation, AIU's 2009 WACOG prices, are higher than the NYMEX average price for 2010 and track very closely to the 2011 prices. (Staff Ex. 25.0, pp. 11-13) As such, the market's current expectation of gas prices demonstrates that AIU's 2008 gas prices were outliers and Staff's proposal more closely corresponds to the expected future prices. As such, the Commission should reject AIU's claims.

7. OPEB Net of ADIT (Accrued OPEB Liability)

The AIU continue to argue that it is possible to "track" specific dollars of revenues to specific components of expense and in turn compare those dollars to amounts contributed to the OPEB trust. The Commission has previously discounted that attempt by the AIU as inappropriate. (Staff IB, p. 33) Furthermore, even if such tracking could be done, the AIU's presumption that the source of funds is determined by whether or not AIU happened to track those funds is not valid. There is no reasonable basis to assume that all available funds are provided by shareholders unless somehow they have been specifically tracked as coming from ratepayers. The AIU has again failed to provide any reason why the Commission should deviate from the position it has previously taken on the same argument. As Staff explained in its Initial Brief, the OPEB Liability represents ratepayer-supplied funds and the Commission should reflect it as a reduction to rate base. (*Id.*, pp. 32-34)

8. Other

D. Recommended Rate Base

1. Electric

Based on the rate bases for the electric utilities originally proposed by CILCO, CIPS, and IP and Staff's proposed adjustments to those rate bases as summarized in Staff's Initial Brief and further supported herein, the electric utility rate base proposed by Staff for CILCO is $308,454,000, for CIPS is $530,832,000, and for IP is $1,461,873,000. (*Id.*, pp. 34-35)

2. Gas

Based on the rate bases for the gas utilities originally proposed by CILCO, CIPS, and IP and Staff's proposed adjustments to those rate bases as summarized in Staff's Initial Brief and further supported herein, the gas utility rate base proposed by Staff for CILCO is $191,987,000, for CIPS is $195,421,000, and for IP is $512,245,000. (*Id.*, pp. 34-36)

III. OPERATING REVENUES AND EXPENSES

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6. Storm Expenses

7. AMR Expense

8. Smart Grid Costs

9. Homer Works HQ Sale

10. Social and Service Club Dues

11. Charitable Contributions

12. Industry Association Dues

13. Advertising Expense

14. Customer Service and Information Expenses

15. Lobbying Expense

16. Rate Case Expense

17. Collateral Expense

18. Company-Use and Franchise Gas

19. Real Estate Taxes

20. Prior Period HMAC

C. Contested Issues

1. Tree Trimming

The AIUs' remarks regarding a "no contact" zone approach to tree trimming (Ameren IB, pp. 69-70) constitute a red herring meant to divert attention away from the immediate issue surrounding the appropriate amount of tree trimming expense to be included in the revenue requirements. Staff presented no testimony regarding the appropriate amount of tree trimming or the time period over which it is to be done. (Tr., pp. 186-187, December 14, 2009) The only issue regarding tree trimming is how much cost is to be included in the revenue requirement.

The AIUs are incorrect in claiming that Staff's adjustment to reduce tree trimming expense for all three companies is mathematically impossible and should be rejected. (Ameren IB, p. 71) It is possible to make such an adjustment when the annual historical average to maintain a 4-year tree trimming cycle at each AIU, calculated for the period January 2005 through June 2009, is less than the pro forma adjustment for the respective AIU. (Staff Ex. 3.0, Sch. 3.05 CIPS-E, CILCO-E, IP-E) The average of costs incurred by each utility over a period of time smoothes the cost variances and provides a reasonable amount of tree trimming expense to include in each respective revenue requirement. (Staff IB, pp. 42-43)

The Commission should pay little heed to the AIUs' lament that Staff's recommendation will be less than required to achieve the four-year tree trimming cycle across the AIUs' entire service territories and that they will not be able to continue reliability-enhancement tree trimming programs. (Ameren IB, pp. 72-73) The AIU have been on 4-year trim cycles since 2004; mid-cycle patrols began in 2004 for AmerenCILCO and AmerenCIPS and 2005 for AmerenIP; and prescriptive trimming began in October 2006 for all three companies. Ameren makes no claim that the amount spent for tree trimming from January 2005 through June 2009, the period over which Staff calculated an annual average, was not sufficient for each utility to meet its tree trimming obligations. (Staff IB, p. 43)

In an effort to legitimize the 2010 budget as the basis for pro forma adjustments to test year tree trimming expense, Ameren discusses the "reasonableness" of the 2010 budget and identifies "evidence" to support that the amount of tree trimming expense projected in the 2010 budget is the appropriate amount of tree trimming expense for the 2008 historical test year. (Ameren IB, pp. 70-71) While a budget may reflect an expected change in operating results, it does not reflect a known and measureable change in operating results, which is the necessary criteria for pro forma adjustments to a historical test year, per 83 Ill. Adm. Code 287.40. (Staff IB, p. 44) Even if the AIU had filed a future test year, the amount of each Company's 2010 budget would not automatically be the appropriate amount to include in the respective revenue requirement. A future test year has its own set of requirements, including review by an independent accounting firm of the assumptions on which the numbers are based. (Tr., p. 182, December 14, 2009)

The AIUs' pro forma adjustments to tree trimming expense, which rely on the 2010 budget, are inappropriate and should not be accepted by the Commission. For ratemaking purposes, the average annual amount of tree trimming expense calculated by Staff for each AIU approximates a more normal level of expense than does the amount spent in any one year. The average annual amount of tree trimming expense proposed by Staff should be adopted by the Commission. (Staff IB, p. 44)

2. Incentive Compensation Expenses

The AIU argue that because the record in its prior rate proceedings indicated that it was reasonable to pass along certain portions of incentive compensation expense to its customers for recovery through rates, similar costs should be allowed for recovery regardless of the record in the current proceedings. (Ameren IB, p. 74) However, the more developed record in the current proceedings demonstrate that the AIU have not met the standard set by the Commission for recovery of incentive compensation expense through base rates. (Staff IB, pp. 12-17) While the AIU opine it has satisfied the standard for recovery (Ameren IB, p. 74), Staff has explained how the evidence provided by the AIU falls short. (Staff IB, pp. 45-46)

The AIU Initial Brief might lead the reader to believe that information regarding customer benefit was provided for both the AIU incentive compensation plans as well as the Ameren Services' ("AMS") incentive compensation plans. (Ameren IB, p. 75) Information included in Ameren Ex. 42.1 was limited to the incentive plans for the AIU; no comparable information was provided for the AMS plans. Thus, no showing of customer benefit was made specific to the AMS plans.

Staff witness Ebrey does agree that customer benefits resulting from the achievement of KPI's are not necessarily tied to a financial measurement. (Staff Ex. 15.0, p. 11) However, her testimony also sets forth an explanation of those types of KPI's, which by the AIU's own description do result in financial savings which should be compared to the cost of achieving those goals. (*Id.*, p. 10) AIU did not provide any type of financial analysis even for those KPI's.

While the AIUs claim to have shown that their incentive compensation plans provide ratepayer benefits (Ameren IB, p. 81), what they have in fact shown is what the plans are **designed** to do with no showing of the **actual results** of the plans.

3. Pension, OPEB and Major Medical Expenses (including Production Retiree Expenses)

The AIU continue to claim that the pension and OPEB expense should be based on the 12 months ending 9/30/09 as the known and measurable amount. However, the actual costs recorded during that 12 month period overstate the actual cost for the 12 months. As indicated in the supplemental testimony filed by AIU witness Stafford, the AIU's pension/OPEB expense had decreased from the January 21, 2009 report to the updated report, dated July 2, 2009, prepared by the actuarial consultant. (Ameren Ex. 25.0, p. 4) Thus, the amounts recorded on the AIU's books from July through December would have been decreased to offset the higher amount accrued each month from January through June 2009.

The AIU mischaracterizes Staff's opinion of the relationship between the amounts provided on the July 2009 valuation report and the amounts recorded on the books of the AIUs at September 2009. (Ameren IB, p. 83) Staff does not acknowledge that those are the "same amounts" but rather that the amounts recorded on the books at September 2009 are **based** on the amounts in the July 2009 report. (Staff Ex. 15.0, pp. 18-19) Since the July report represents a 12 month period and the amounts on the books at September 2009 are for a 9 month period, the amounts would not reasonably be the same.

The AIU further claim that no reason, rationale or record evidence is cited to support the assumption that the amounts booked through September 30, 2009 could change. This claim is erroneous. During cross examination, Staff witness Ebrey stated that the workforce reduction that occurred in November and December 2009 (resulting in an adjustment to which the AIU agreed in theory) would, in her opinion, meet the definition of a significant event (Ameren Ex. 54.0, p. 3) that would in turn impact the expense for 2009, yet would not be reflected in the September 30, 2009 balance per AIU books. (Tr., pp. 787-788, December 17, 2009)

Finally, the AIU continue to offer into evidence the December 2009 actuarial study that will not be available until mid-February 2010. (Ameren IB, p. 84) As Ms. Ebrey stated during cross examination, holding the record open for information that does not exist at the time of hearing as support for a pro forma adjustment is clearly contrary to the known and measurable criteria. (Staff IB, pp. 47-48)

4. NESC Expenses

Ameren and IBEW disagree with Staff witness Rockrohr's recommendation that the Commission disallow certain NESC-related repair costs associated with installing missing parts onto existing distribution facilities in order to correct the installation so that it complies with the National Electrical Safety Code ("NESC"). (Ameren IB, p. 85; IBEW IB, p. 9) Ameren acknowledges that the Commission, in its Final Order in Docket Nos. 07-0585 - 0590 (Cons.), determined that "...ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." (Ameren IB, p. 86) Ameren claimed that adding the required missing parts to its existing distribution facilities did not cause the utility to rebuild existing infrastructure or duplicate work previously performed, and so that recovery of these costs from ratepayers would not conflict with the Commission's Final Order in Docket Nos. 07-0585 - 0590 (Cons.). (*Id.*, pp. 85-89)

Staff explained that, since the utility had already installed the down guys, overhead guys and metal underground risers that required the missing parts per NESC requirements, adding the missing parts to the AIUs existing facilities was not “new work.” (Staff IB, p. 51) Even though Ameren acknowledged the Commission’s direction in its Final Order in Docket Nos. 07-0585 - 0590 (Cons.), and acknowledged that the utilities should have been aware of the requirement for the missing part and installed the part at the time of initial construction (Ameren Ex. 35.0, pp. 4-5), Ameren proposed to recover estimated test year capital costs and expenses for adding the NESC-required missing parts.

Staff objects to Ameren’s proposed recovery because AIU’s facilities were improperly constructed at the time of initial construction. The utilities failed to install parts required by the NESC. AIU’s proposal in this proceeding to charge ratepayers its estimated test year costs to install missing parts is inconsistent with the Commission’s Order in Docket Nos. 07-0585 - 0590 (Cons.). (Staff Ex. 24.0R, p. 9)

Ameren also contended that Staff was incorrect in stating that the cost of installing the missing parts at the time of initial construction would have been negligible. (Ameren IB, p. 89) Despite Ameren’s contention, Staff’s statement is true. Staff witness Rockrohr explained why Ameren’s estimated test year costs to add the missing parts does not represent what the utility’s costs would have been at the time of initial construction, and why actual installation costs would have been negligible. (Staff Ex. 24.0R, pp. 9-10)

In summary, Ameren contends that because it did not install the missing parts that the NESC requires at the time of initial construction, ratepayers did not previously pay for the part or the labor to install the part. (Ameren IB, pp. 89-90) Staff, however, points out that "...AIU could not demonstrate whether or not ratepayers have already paid for the missing parts at these locations with NESC violations." (Staff Ex. 24.0R, p. 11) Staff further suggests that the very fact that Ameren was not aware that the required parts were missing casts doubt on its knowledge as to whether or not ratepayers previously paid for the part. Regardless of whether or not ratepayers previously paid for the installation of the missing parts, in every case, utility costs for installing the missing part at the time of initial construction would have been negligible. (Staff IB, p. 51) AIU stated it does not know its actual test year costs to install these missing parts, stating it would be difficult, if not impossible, to determine a precise breakdown of labor costs for NESC and non-NESC repairs. (Ameren Ex. 11.0E (Revised), p. 11) Clearly Ameren's recovery of its estimated test year cost for installing NESC-required missing parts would be very unfair to ratepayers who may have already paid for them, and such a recovery would be inconsistent with the Commission's Final Order in Docket Nos. 07-0585-0590 (Cons.). The Commission should adopt Staff's recommendation and disallow these costs.

IBEW's disagreement with Staff's position appears to be associated with its concern that Ameren's reduced recovery for NESC-related repairs could lead to Ameren reducing expenditures for other maintenance projects, which could have a negative impact on service reliability, and could result in a loss of jobs. (IBEW IB, pp. 9-10) Staff does not know whether or not IBEW's concern is valid. Though Staff does not think it would be a good idea to do so, Ameren could decide to reduce its maintenance expenditures for any number of reasons, independent of the Commission's decision regarding this NESC issue. While potential job loss might be a legitimate concern, Staff does not believe the Commission should base its decision upon this concern.

5. Amortization of IP Merger Expense/Regulatory Asset

The AIU agree with Staff's adjustment to amortize the final 8 months of the IP Regulatory asset over the 2 year period that rates in these cases are anticipated to be in effect. (Ameren IB, p. 91) Staff does not take issue with the AIU adjusting their regulatory asset amortization, as recorded on the books of Ameren IP, to match the amount and 2 year period proposed by Staff's adjustment. (*Id.*, p. 92)

6. Economic Development Expenses

The Commission should adopt Staff's adjustments to remove AMS Economic Development ("ED") Department labor and labor-related costs from each Company's respective revenue requirement, as presented in Staff Ex. 18.0R, Schedule 18.06. The costs in dispute are for commercial customer recruitment and retention which are prohibited by 220 ILCS 5/9-225 because the costs are promotional, institutional, or goodwill in nature. Thus, the costs are not recoverable in rates. The costs are primarily for the benefit of investors, and should not be the responsibility of ratepayers.

As described in its initial brief, AIU provides, through the ED Department, numerous services to attract and retain business investment in the communities in which AIU provides utility service. (Ameren IB, pp. 92-94) While such services may have secondary effects beneficial to those communities (*Id*.), the services are geared primarily towards increasing AIU's customer base (Tr., p. 78, December 14, 2009), thereby increasing AIU revenues (Tr., pp. 874-875, December 17, 2009). The costs of these services should be the responsibility of the investors, not the ratepayers. (Staff Exhibit 18.0R, p. 16)

In its initial brief, AIU discusses *projected* creation of jobs and new project investment. (Ameren IB, pp. 93-94) Staff does not oppose job creation, nor does Staff oppose economic development arising from new project investment. Although Staff is sensitive to the need for job creation and new project investment, the economic development costs described in this docket, when taken as a whole, are not recoverable. (Staff Exhibit 18.0R, p. 16-18)

In its initial brief, AIU claims “No party has disputed either the essential services provided by the Department during these projects or the tangible benefits enjoyed by the AIU customers as a result.” (Ameren IB, p. 94) This statement is misleading. While no party has disputed the services provided or the benefits AIU claims customers enjoy, Staff specifically states in its rebuttal testimony that the ED costs are not necessary in providing utility services. (Staff Ex. 18.0R, p. 16) In other words, Staff’s position is that ED services are not essential. AIU’s own witness readily admitted AIU would “certainly provide utility service in the absence of such programs.” (Tr., pp. 80-81, December 14, 2009) As such, one can hardly consider the ED services essential.

AIU incorrectly states, “Mr. Bridal agreed that the Department provides an essential function by answering questions from customers about the provision of utility service, including questions regarding expanding service or consuming service more efficiently.” (Ameren IB, p. 94) In fact, in the referenced cross-examination, Mr. Bridal stated only that it sounded reasonable that a utility would be fulfilling an essential service by answering customers’ questions and concerns regarding provision of service.

He made no remarks regarding the ED Department, expansion of service, or consuming service more efficiently. (Tr., pp. 868-869, December 14, 2009)[2]

AIU states, "Mr. Bridal agreed that the AIUs' customers benefit from the AIUs' efforts to actively increase their customer base because doing so spreads the fixed operating costs of the AIUs across a larger number of customers." (Ameren IB, p. 94) More accurately, Mr. Bridal agreed that at a <u>*point in time*</u>, the addition of customers to the existing customer base may provide a benefit to existing customers by spreading out fixed operational costs. (Tr., pp. 872-873, December 17, 2009) AIU excludes from its brief the fact that Mr. Bridal stated, during redirect cross-examination, that the addition of new customers between rate cases (e.g., between points in time) would have the effect of increasing company revenues; however, costs included in rates would remain the same.[3] (Tr., pp. 873-875, December 17, 2009) Essentially, customer count and revenues would increase, but the costs and number of customers those costs are spread across would remain unchanged until a <u>*point in time*</u> (e.g., the next rate case). At the time of the next rate case, fixed costs to be spread across the new, increased number of customers would also increase due to the costs of new plant or increased O&M costs incurred to serve the new customers. (*Id*.)

Considering the guidance of Section 9-225 of the Act and the record in this docket, the Commission should adopt Staff's adjustment to remove ED costs from each Company's revenue requirement.

[2] It should be noted, however, that a utility's costs for responding to customer inquiries, by themselves, may indeed be recoverable under the Public Utilities Act. If such costs are included within ED costs, there is nothing in the record which could be used to separate these types of costs from ED costs as a whole.

[3] Costs are set during a rate case, and cannot be spread among incremental customers until the next rate case.

7. Workforce Reduction

The AIU cite Docket No. 05-0597 (the “ComEd case”) as precedent for the approval of severance costs associated with the workforce reduction which took place in November and December 2009. (Ameren IB, p. 96) The severance costs in that case were related to a specific Cost Savings Program called the Exelon Way program. (Order, Docket No. 05-0597, July 26, 2006, p. 90) The specifics of that program were provided under Section 285.3215, which incents a utility to initiate cost savings programs and outlines the specific detail required for recovery. No similar information was provided by the AIU in the current cases. In fact, the AIU specifically excluded this information from their filing. (Part 285.1000 Schedule A-1: Summary of Standard Information Requirements for each utility, Schedule C-22 under Section 285.3215) Only in response to discovery generated by a press release by Ameren in early September 2009 did the AIU provide to Staff the information about the workforce reduction. No detail of savings was provided to Staff until late October. Since the circumstances surrounding the ComEd case were so different from the AIU cases, the conclusion in that case is not instructive for this case. Severance costs related to the AIU workforce reduction should not be allowed for recovery.

Ameren argues that Staff’s adjustment double counts the payroll tax component of the workforce reduction adjustment. (Ameren IB, p. 97) Staff explained the error in the AIU payroll tax calculation related to the workforce reduction in its Initial Brief. (Staff IB, p. 58) That discussion will not be repeated here.

In the Appendices to its Initial Brief, Staff revised its rebuttal position so that incentive compensation costs already removed from the operating statement were not double counted. Staff also reflected the jurisdictional allocators included in Ameren Exhibit 51.9 in its revised schedules.

8. Electric Distribution Tax/Public Utilities Revenue Act Tax

Ameren characterizes Staff's position to disallow the increase in the Electric Distribution tax as extreme, yet fails to recognize and respond to Staff's main concern with the increase. (Ameren IB, p. 98-99) Put simply, the AIU has not demonstrated that an overall increase in its share of the Electric Distribution tax will occur; therefore, no increase in the expense is warranted. Thus, Staff's position disallowing the increase to expense should be approved.

9. Transportation Fuel Expense

AIU's discussion in its Initial Brief regarding the just and reasonableness of transportation fuel costs depicted in AIU's proposed method of calculating an average gasoline and diesel fuel price raised four points that Staff disputes. First, AIU claims the average gasoline and diesel fuel prices that it proposed are more closely in line with the latest Energy Information Administration ("EIA") forecasts than the average gasoline and diesel fuel price proposed by Staff. Second, AIU states that Staff should agree that 12 months of fuel pricing data is too narrow of a period to calculate an average gasoline and diesel fuel price. Third, AIU claims that Staff selectively relied on fuel pricing data from the second half of 2008 in its proposed calculation of AIU average fuel costs. Finally, AIU asserts that 2010 EIA forecasts do not foreclose the possibility that the prices AIU experienced in 2008 could not also be experienced in 2010 when its rates go into effect. Staff discusses each of these points below.

AIU first concern is that the average gasoline and diesel fuel prices that it proposed are more closely in line with the latest Energy Information Administration ("EIA") forecasts than the average gasoline and diesel fuel price proposed by Staff. (Ameren IB, p. 102) Staff does not dispute that the December 2009 EIA forecasts for 2010 prices for gasoline and diesel fuel rose slightly since Staff filed its rebuttal testimony. However, Staff would note its use of the August 2009 EIA forecasts was to show that AIU's 2008 transportation fuel prices were price outliers. (Staff Ex. 26.0R, pp. 16-17) However, the December 2009 EIA forecast for transportation fuel prices in 2010 still demonstrate that AIU 2008 gasoline and diesel fuel prices are outliers, which support the arguments Staff made regarding AIU's proposal.

AIU also argues that since its proposed transportation fuel price more closely resembles the average gasoline and diesel fuel prices forecasted by the EIA in December 2009 for calendar year 2010 then Staff's proposed prices, the Commission should adopt its proposal and reject Staff's proposal. (Ameren IB, pp. 100-101) However, AIU selected a historical test year where only known and measureable changes are considered. As such, forecasted fuel prices are not known and measureable. Instead, what is known and measurable are the actual 2009 prices that were included in the EIA December 2009 report. This report showed the actual average price data for transportation fuels for the January 2009-December 2009 were $2.40/gallon for gasoline and $2.47/gallon for diesel fuel. (AIU Cross Exhibit Seagle No. 9) These values more closely correspond to Staff's proposed numbers, $2.51/gallon and $2.78/gallon, then AIU proposed average fuel prices for gasoline and diesel fuel, $2.88/gallon and $2.96/gallon, respectively. As such, Staff continues to support the use of its proposed adjustment for transportation fuels.

AIU's second point claimed that 12-months of fuel pricing data is too narrow of a period to calculate an average gasoline and diesel fuel price. (Ameren IB, p. 102) Staff disagrees. Staff noted that its 12-month average gasoline and diesel fuel price is the appropriate method for utilization in the calculation of transportation fuel costs for AIU because its proposal is consistent with another proceeding where the same issue, transportation fuel, was raised. Specifically, Staff noted that it relied on one year (12-months) of EIA data to value transportation fuels in the Peoples Gas and North Shore Gas rate case in Docket Nos. 09-0166/090167 (Cons.). (Staff Ex. 13.0, p. 22)

AIUs also noted that Staff is inconsistent because it made an adjustment for Account 887, Maintenance of Mains, that utilized a three-year normalization method (Ameren IB, pp. 101-102) which as the AIUs claim is not consistent with the 12-month average that Staff proposed for calculation of transportation fuel costs. However, Staff asserts that the proposal regarding Account 887, discussed in detail in Staff's Initial Brief at pages 66-68 is unique to the circumstances associated with that issue. Therefore, Staff's recommendations are not inconsistent since its approach accounts for the unique circumstances associated with each of its adjustments.

AIU's third topic claimed that Staff selectively relied on fuel pricing data from the second half of 2008 in its proposed calculation of AIU average fuel costs. (*Id.*, p. 102) This misrepresents Staff's position. Staff demonstrated that AIU's original position that placed reliance on only 2008 transportation fuel prices was inappropriate due to the 2008 transportation fuel prices being price outliers. (Staff Ex. 26.0R, pp. 16-17) As a result, Staff recommended the use of the most recent 12-month period for valuing the transportation fuel. Staff did not pick this period arbitrarily, but given AIU's selection of a historical test year, Staff could only rely on known and measurable changes. As such, Staff used the most recent 12-month period because that was the information available to Staff at the time it filed its testimony. (Staff Ex. 13.0, p. 22; Staff Ex. 26.0R, pp. 16-17)

AIU's final point was that 2010 EIA forecasts do not foreclose the possibility that the prices AIU experienced in 2008 could not also be experienced in 2010 when its rates go into effect. Staff agrees that no one knows what transportation fuel prices AIU or anyone else will experience in the future. However, what is known is that the current forecasts do not show transportation fuel prices returning to the 2008 levels, which demonstrates Staff's point regarding 2008 transportation fuel prices being price outliers. However, Staff believes that even though the 2010 EIA forecast has been revised upward the basic comparison Staff provides in its initial brief, pp. 61-63, still shows that fuel prices experienced in mid-2008, $4/gallon range, will not be experienced by AIU when rates granted by the Commission go into effect. (Staff Ex. 27.0R, pp. 16-17)

10. Account 887 Expense –Maintenance of Mains

AIU's discussion in its Initial Brief regarding the just and reasonableness of its Account 887 expense raised one additional point that Staff did not already fully address in its initial brief, pages 66-68. Specifically, AIU asserts that it did provide a detailed explanation of why the AIUs Account 887 expense has increased so dramatically from 2006-2008. (Ameren IB, p. 106) Staff disagrees.

Staff attempted to acquire detailed information regarding how a utility's recurring business activities affect separate accounts differently, including Account 887. Staff issued multiple data requests that attempted to establish what, if any, business activities had changed between 2006 and 2008 and how that impacted Account 887. (Staff Ex. 13.0, p. 17; Staff Ex. 26.0R, pp. 11-13) Staff found that the AIU's testimony and responses to its data requests were, at best, insufficient in order for Staff to determine if AmerenIP's Account 887 expense was just and reasonable.

Staff noted that AmerenIP's data request responses just provided a general overview with no specific data regarding the dramatic increase in Account 887 expense. (*Id.*, pp. 12-13) Staff also noted that the responses to Staff data requests indicate that AmerenIP was unable to track the costs associated with this account down to a precise dollar amount from 2006-2008. In other words, AmerenIP was unable to explain or provide any basis for why the costs it placed into Account 887 had more than tripled from 2006 through 2008. (*Id*., p. 13) Finally, after Staff's multiple attempts to obtain useful information, AmerenIP said it will not provide any further information regarding Account 887 to support the drastic increase in its requested Account 887 amounts. (*Id.*) Therefore, Staff concluded that AmerenIP was unable to support the large increase in Account 887 expense amounts and therefore Staff continues to dispute the AIUs method of normalization, the three-year period ending September 2009, because of the AIUs inability to provide any detailed information regarding the increase of Account 887 expense. This lack of detailed information makes it impossible for Staff to verify that AIUs proposed Account 887 expense is just and reasonable.

Given the above explanation regarding AmerenIP's Account 887 expense, Staff continues to recommend that the Commission reduce AmerenIP's expense for Account 887 by $665,000.

11. Injuries and Damages Expense

12. Overall Reasonableness of O&M Expenses

13. Other

D. Recommended Operating Income/Revenue Requirement

1. Electric

Based on the operating expense statements for the electric utilities originally proposed by CILCO, CIPS, and IP and Staff's proposed adjustments to operating revenues and expenses as summarized in Staff's Initial Brief and further supported herein, the total electric utility delivery services net operating income proposed by Staff for CILCO is $25,540,000, for CIPS is $42,785,000, and for IP is $132,300,000. (Staff IB, p. 70)

2. Gas

Based on the operating expense statements for the gas utilities originally proposed by CILCO, CIPS, and IP and Staff's proposed adjustments to operating revenues and expenses as summarized in Staff's Initial Brief and further supported herein, the total gas utility net operating income proposed by Staff for CILCO is $15,262,000, for CIPS is $15,028,000, and for IP is $44,640,000. (*Id.*, pp. 70-71)

IV. COST OF CAPITAL/RATE OF RETURN

A. Overview

B. Capital Structure

1. Central Illinois Light Company (CILCO)

a. Preferred Stock Balance – Immaterial Difference

b. Short-Term Debt Balance - Resolved

c. Long-Term Debt Balance – Immaterial Difference

d. Common Stock Balance –Resolved

2. Central Illinois Public Service (CIPS)

a. Preferred Stock Balance – Resolved

b. Short-Term Debt Balance - Resolved

c. Long-Term Debt Balance – Resolved

d. Common Stock Balance – Resolved

3. Illinois Power Company (IP)

a. Preferred Stock Balance – Resolved

b. Short-Term Debt Balance – Resolved

c. Long-Term Debt Balance – Contested

The Company alleges that Ms. Phipps' adjustments to IP's capital structure are based on hindsight and, therefore, improper. (Ameren IB, pp. 130-132) Ameren states:

> Another key factor impacting the need for this financing and the requirement to improve AmerenIP's liquidity position was the condition of the capital markets and bank markets…Lehman Brothers filed for bankruptcy the month before and the markets were rife with rumors around the potential failure of other financial institutions including, among others, Citibank, Wachovia and [Goldman Sachs]… After its bankruptcy filing, Lehman Brothers was no longer funding loan requests under these facilities and many feared others would follow. At the time of its bankruptcy filings, Lehman Brothers represented $71 million of the $1 billion in credit facilities AmerenIP could directly access (under its $350 million of borrowing sub-limits). The other three institutions listed above represented a combined total of approximately $265 million under these facilities. (*Id.*, pp. 130-131)

First, Ameren mischaracterizes Ms. Phipps testimony when it states, "[a]t the hearing, Ms. Phipps acknowledged these circumstances existed in the financial markets at the time." (*Id.*, p. 131) In fact, Ms. Phipps' acknowledged that she was aware that the

Company claimed it took into account the circumstances in the financial markets in October 2008:

> Q. Is it your understanding that the Company said, correctly or not, that the Company took into account the circumstances in the financial markets in October of 2008?
>
> A. The Company said that, yes.
>
> (Tr., p. 261, December 15, 2009)

Ms. Phipps also testified that her adjustment was not based on circumstances in the financial markets in the fall of 2008 but was based on IP's short-term bank loans outstanding and IP's daily short-term debt and cash balances during that time. Based on those factors, Ms. Phipps concluded that IP did not require the additional $50 million long-term debt it issued. (Tr., pp. 260-261, December 15, 2009) The condition of the financial markets is not pertinent given the Commission Order that authorized IP's October 2008 debt issuance required that IP use any proceeds from issuing long-term debt to repay outstanding short-term debt. (Order, Docket No. 08-0565, October 15, 2008, pp. 4-5) If IP preferred long-term financing authority to enhance its liquidity position in light of the condition of the financial markets, then IP should have requested Commission authority to issue long-term debt or equity for that purpose. Instead, IP and Ameren created an unnecessary $60 million money pool loan from Ameren Corp. to IP so that IP could boost the amount of its long-term debt issuance from $350 million to $400 million under the authority the Commission granted in Docket No. 08-0585.

Second, contrary to the Ameren Initial Brief, the AIU credit facilities lost not $71 million, but $21 million of borrowing capacity since Lehman Brothers assigned $50 million to another lender on September 17, 2008, only two days after its bankruptcy filing.[4] (Staff IB, p. 81) Moreover, on September 18, 2008, three days after the Lehman Brothers' bankruptcy filing, Ameren Corp. issued a Form 8-K to investors stating that Ameren Corp. and its subsidiaries did not believe the potential reduction in available capacity under credit facilities would materially affect their liquidity. IP issued $400 million 9.75% bonds on October 23, 2008, which was more than one month after the Lehman Brothers' bankruptcy filing. During that month, no other lenders under the credit facilities filed for bankruptcy and on October 8, 2008, IP's board of directors declared dividends on its common stock not to exceed $15 million, which suggests that IP's board of directors was not concerned about enhancing IP's liquidity position. In fact, IP claimed that the $15 million dividend could reasonably be declared and paid without impairment of the ability of the utility to perform its duty to render reasonable and adequate service at reasonable rates. (Tr., pp. 232-234, December 15, 2009) Clearly, IP is trying to have it both ways. IP wants the Commission to believe that the capital markets were sufficiently uncertain to have IP issue $50 million of 9.75% bonds in excess of its credit facility borrowings to enhance liquidity, but not so uncertain that IP could not pay $15 million in common dividends without impairment of its ability to render reasonable and adequate service at reasonable rates.

Ameren argues further:

> …AmerenIP was concerned about renewal one year in advance because… Moody's had already been publicly signaling its focus on the renewal of IP's, and the other AIUs', bank facilities, noting this in August, and September, 2008 credit reports. Moody's further reinforced this view in an October 2009 Special Comment "Investor-Owned Utilities Face

[4] IP did not issue the 9.75% bonds until October 23, 2008, over one month after the Lehman Brothers bankruptcy and its assignment of $50 million of its credit facility commitment to Commerzbank AG. (Staff Ex. 5.0R, Schedule 5.03 IP; Staff Ex. 19.0R, p. 11)

> Significant Bank Facility Refinancing Risk as Substantial 2011-2012 Maturities Approach." (Ameren IB, p. 133)

First, IP only required $350 million long-term debt to repay outstanding bank facility borrowings. Second, replacing the short-term debt with long-term debt did nothing to address concerns which Moody's may have had regarding IP's ability to renew its bank facilities or any similar concerns it may have had regarding CILCO or CIPS. Third, even after it issued the $50 million in excess 9.75% bonds, IP entered into the 2009 credit facility with the same credit sublimit it had under its previous credit facilities. (Staff Ex. 19.0R, Attachment G) In other words, IP determined that its October 2008 decision to issue $50 million in excess 9.75% bonds did not enhance its liquidity sufficiently to reduce the sublimit it needed by a single dollar despite the much higher cost of maintaining that sublimit under the 2009 credit facility. Finally, Ameren's reference to the October <u>2009</u> Moody's publication is another red herring since it was published one year after IP issued $400 million bonds and four months after the AIU closed on the Illinois Facility in June 2009. Interestingly, the Company's citation to the October 2009 Moody's report confirms little more than Moody's is perpetually concerned with utilities' ability to renew credit facilities. Taken to its logical conclusion, all utilities should issue more long-term debt than they require as a shield against credit facility renewal risk.

The Commission should reject Ameren's misplaced and irrelevant arguments. For all the reasons set forth herein, and those reasons provided in Staff's Initial Brief at pages 75-82, the Commission should adopt Staff's proposed capital structure for IP.

d. Common Equity Balance – Contested

According to Ameren, the March 2009 common equity infusion was "an effort to bolster AmerenIP's credit quality by enhancing its credit metrics and de-levering its capital structure." (Ameren IB, pp. 133-134) Staff counters that the common equity infusion was only necessary because IP issued $400 million more bonds to refund approximately $350 million outstanding short-term bank loans during October 2008. (Staff IB, p. 82) On this issue, Ms. Phipps testified that the March 2009 common equity infusion offsets the $50 million excess long-term debt that IP issued during October 2008. Specifically, Ameren proposes a capital structure for IP that comprises 44.1% common equity; Staff proposes an adjusted capital structure for IP that comprises 43.5%. (Tr., p. 263, December 15, 2009) Not only is the equity ratio in Staff's adjusted capital structure very close to Ameren's proposed equity ratio, but comparing those figures reveals that the March 2009 equity infusion combined with IP's October 2008 bond issuance effectively eliminated any advancement towards IP's "stated equity ratio target in the range of 50%-55%." (Ameren IB, p. 134)

Ameren also argues:

> …Moreover, in an AmerenIP-specific credit opinion published by Moody's the day following the announcement of the upgrade, Moody's cited concerns around additional pressure on AmerenIP's financial metrics as a potential driver or factor which could drive the rating down. Common equity infusions are helpful for financial metrics and would thus act as an offset to any factor placing negative pressure on the metrics. (*Id.*, p. 135)

Moody's August 14, 2009, credit opinion for Illinois Power Company states, "[IP] also issued $400 million of senior secured notes in October 2008 at a relatively high rate of 9.75%, which increased long-term debt levels and interest expense." (Staff Ex. 19.0R, Attachment B) All else equal, increases in debt levels and interest expense negatively pressure four of the six financial metrics that Moody's evaluated for IP. (Staff Group Cross Ex. 1-C, p. 28) This supports Staff's view that the $58 million common equity infusion was due to IP's issuance of $50 million more long-term debt than required to refund its short-term bank loans.

Furthermore, the Ameren Initial Brief mischaracterizes Staff testimony when it claims, "Ms. Phipps acknowledges that AmerenIP's objectives were worthwhile." (Ameren IB, p. 134) Ms. Phipps' testimony actually states:

> Yet, I did not adjust IP's common equity because the objectives noted by Mr. Nickloy are not worthwhile. I recommend removing $50 million long-term debt that IP did not require and the subsequent equity infusion that was intended to bolster IP's equity ratio after the Company issued $50 million more bonds than it required to repay its short-term bank loans. (Staff Ex. 19.0R, p. 14)

Finally, the Ameren Initial Brief refers to a September 2009 equity infusion and argues:

> The capital markets also were tentative and AmerenIP was facing a near-term $250 million long-term debt maturity. In June, once it became apparent that AmerenIP would be able to successfully complete the renewal of its bank facilities, it elected to fund this long-term debt with cash. (Ameren IB, p. 134)

Both the June 2009 retirement of $250 million of long-term debt and the September 2009 equity infusion are completely irrelevant because they occur three to six months beyond IP's March 31, 2009 capital structure measurement date. Worse, attempting to justify a March 2009 common equity infusion on the basis of subsequent events is exactly the type of hindsight review that Ameren argues is inappropriate in evaluating its decision to issue the extra $50 million in 9.75% bonds.

For all the reasons set forth herein, and those reasons provided in Staff's Initial Brief at pages 82-84, the Commission should adopt Staff's proposed capital structure for IP.

e. Staff's Alternative Recommendation

Page 84 of Staff's Initial Brief describes the basis for and the calculation of Staff's alternative recommendation for IP.

C. Cost of Preferred Stock – Resolved for CILCO, CIPS and IP

D. Cost of Long-Term Debt

1. CILCO – Contested

Ameren opposes Staff's adjustments to the interest rate for CILCO's December 2008 long-term debt issuance. Ameren argues that Staff makes unfounded assumptions regarding CILCO's credit rating. Ameren states:

> …the rating agencies use a combination of qualitative factors along with quantitative analysis in determining an issuer's credit ratings, and are ultimately the final arbiters of credit ratings. Any adjustment based on an assumption that CILCO would be entitled to a higher rating is unfounded. (Ameren IB, p. 138)

As required by statute, Staff properly removed any incremental cost due to CILCO's affiliation with non-utility affiliates, including AERG and CILCORP, because Section 9-230 of the Act specifically prohibits including in utility rates any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies. Section 9-230 specifically states:

> In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission **shall not include any** (i) incremental risk, (ii) increased cost of capital … which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies. (220 ILCS 5/9-230) (emphasis added)

In *Illinois Bell Tel. Co. v. Illinois Commerce Comm'n*, the Appellate Court specifically reiterated this prohibition and specifically pointed to the word "any" to interpret the legislature's intent to "modify its prohibition of considering incremental risk or increased cost of capital in determining a reasonable ROR." 283 Ill.App.3d 188, 205-207 (2nd Dist. 1996). Accordingly, any increase must be excluded and the Commission has no discretion to consider the causes of a utility's increased cost of capital due to its affiliation with a non-utility company. The Court went on to state, "We hold that if a utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its ROR calculation." *Id.* The Court suggested that if the Commission found that an affiliation caused an increased cost of capital, the Commission would have to determine the amount of this increase and then remove it from the ROR calculation. *Id.* at 210.

It is the responsibility of Staff to bring these adjustments concerning non-utility affiliates to the Commission's attention. A utility ultimately bears the burden of proving that its proposed rates are just and reasonable. (220 ILCS 5/9-201(c)) However, one of the steps the Commission is mandated to take is to ensure if a utility's exposure to risk is one iota greater, or if it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, such increases do not enter into its rate of return calculation. Such evidence has been presented in this case and must be considered by the Commission.

Staff is not making any unfounded assumptions about CILCO's credit rating given that the rating agencies expressly state that non-utility affiliates affect CILCO's credit rating. (Staff IB, pp. 85-86 and 88) Specifically, as required by law, Staff adjusted CILCO's embedded cost of long-term debt in order to remove the effects the higher business risk profile associated with CILCO's non-utility affiliates by estimating the interest rate for five-year secured bonds that is commensurate with CILCO's lower risk delivery service operations. Ameren complains, "Ms. Phipps cannot step into the shoes of the rating agencies and reasonably opine that the credit ratings for AmerenCILCO would be any different than they are today if it no longer had an unregulated generation subsidiary and/or was no longer owned by an intermediate parent company." (Ameren IB, p. 138) However, in making her adjustment, Ms. Phipps thoroughly examined ratings reports and publications regarding the Moody's and S&P rating methodologies. (Staff IB, pp. 85-90)

For all the foregoing reasons, as well as those set forth in Staff's Initial Brief at pages 85-90, the Commission should adopt Staff's recommended embedded cost of long-term debt for CILCO.

2. CIPS – Resolved

3. IP – Contested

The Ameren IB errs when it states, "Mr. O'Bryan testified that IP's embedded cost of long-term debt was 8.088% as of March 31, 2009." (Ameren IB, p. 139) The 8.088% proposal, which Mr. O'Bryan presented in direct testimony, reflected a pro forma adjustment that Mr. O'Bryan removed in rebuttal testimony, resulting in a 7.94% embedded cost of long-term debt for IP. (Ameren Ex. 37.1, p. 3; Ameren Ex. 37.3, p. 2) Staff and the Company disagree on the embedded cost of long-term debt for IP for the reasons set forth on page 91 of Staff's Initial Brief.

E. Cost of Short-Term Debt including Bank Commitment Fees

Ameren opposes Staff's calculation and allocation of bank commitment fees for the AIU. Ameren argues that Staff's allocation of facility costs is based on unfounded assumptions regarding the both the cost for lender commitments under an $800 million credit facility (versus aggregate credit facilities totaling $2 billion) and the amount of short-term borrowing capacity Ameren Corp. will use. (Ameren IB, pp. 140 and 142) Ameren is wrong. Staff's analysis assumes nothing, but instead relies on the plain wording of the Arrangers Fee letter Ameren signed with the 2009 credit facility banks. (Staff Ex. 19.0R, Attachment G) In contrast, Ameren wants the Commission to assume that if Ameren had agreed to a smaller credit facility, its bank commitment rate would have been higher. The facts demonstrate otherwise. The Ameren commitment fee is set on the basis of the size of <u>individual</u> bank commitments, not the size of the aggregate commitment. (*Id.*) The only two examples Ameren cited in support of its argument that the commitment fee rate goes down as the credit facility size goes up, do not disclose how those fee rates were set. Therefore, they provide zero insight into the relationship between aggregate size of a credit facility and the commitment fee rate.

Ameren states:

> The objective of allocating the costs of the facility is to do so fairly so as to not overcharge or undercharge the AIUs fair share of the fees. Mr. O'Bryan achieves this result by allocating the total bank facility fees by each borrower's proportion of the total borrower sublimits under the facility… This method of allocation is fair in that it does not show any bias toward any borrower beyond what its individual sublimit implies… Under Ms. Phipps' approach, the AIUs could borrow over 79% of the available facility… but bear just 62.5% of the cost. Weighting cost responsibly in proportion to sublimits is far more reasonable. (Ameren IB, p. 143)

Ameren's statements regarding the objective of allocating facility costs are misplaced. The Commission must remove <u>any</u> incremental cost due to the AIUs' affiliation with non-utility affiliates, pursuant to Section 9-230 of the Act, which prohibits including in utility rates any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies. As Mr. O'Bryan explains:

> The upfront and facility fees are fixed expenses paid on the entire credit facility and do not change nor have any relationship to the amount of funds borrowed from the facility. The Company would still owe all of these fees throughout the life of the facilities whether or not they borrowed one dollar from them. These costs, therefore, do not reflect the costs of drawing from these facilities but rather the cost of having access to these facilities. (AmerenCILCO Ex. 13.0G, p. 7; AmerenCILCO Ex. 13.0E, p. 7; AmerenCIPS Ex. 13.0G, pp. 6-7; AmerenCIPS Ex. 13.0E (Revised), pp. 6-7; AmerenIP Ex. 13.0G (Revised), p. 7; AmerenIP Ex. 13.0E (Revised), p. 7)

Using the AIU methodology to allocate bank commitment fees for a credit facility with overlapping sub-limits would result in the AIU paying fixed facility costs for $543 million borrowing capacity,[5] $43 million of which AIU will be unable to access whenever Ameren Corporation draws more than $257 million of its $300 million maximum borrowing sub-limit. Even if the AIU methodology reasonably allocates commitment fees, it is not lawful since it would require the AIU to pay for access to bank commitments that a non-utility affiliate might prevent.[6]

According to the AIU, Ameren Corp. has access to $1.3 billion of credit facilities outside of the Illinois Facility at a rate that is slightly lower than the rate that it can borrow from the Illinois Facility. (Ameren IB, p. 145) This argument has two shortcomings. First, it fails to reveal that the amount and duration of this benefit is limited. Specifically, the declining lenders' commitments expire on July 14, 2010. (Staff

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[5] $543 million is 67.9% of $800 million. In contrast, Staff's methodology would require the AIU to pay for their $500 million of "uninterruptible" borrowing capacity.

[6] The Appellate Court ruled that 220 ILCS 5/9-230 requires the Commission to apply an absolute standard rather than a reasonableness standard. *Illinois Bell Telephone Company vs. Illinois Commerce Commission, 283 Ill.App.3d 188 (2nd Dist.1996).*

IB, p. 98) Second, it raises the question of why Ameren decided to replace the Illinois Facility rather than amend and restate it,[7] thus giving the AIU access to lower cost funds from "Declining Lenders."[8] (*Id.*, pp. 98-99) That is, if Ameren had amended and restated the Illinois Facility, then the AIU could have received a lower borrowing rate from declining lenders just as Missouri Facility borrowers did.

Ameren argues that Staff ignores that Ameren Corp. could act as a "lender of last resort" to the AIU when their individual borrowing sub-limits are at their maximum and there is no additional liquidity in the money pool. (Ameren IB, p. 142) Ameren states further:

> For example, this was the case between October 27, 2008 and October 29, 2008, when Ameren lent between $4.1 million and $13.6 million into the utility money pool at a time when AmerenCILCO's credit facilities sublimit total of $150 million was at capacity and the other AIUs did not have any additional funds to lend. (*Id.*)

However, CIPS and IP had $135 million and $350 million available borrowing capacity, respectively, under their credit facilities between October 27 and 29, 2008. Moreover, IP was loaning the utility money pool between $83.5 million and $89.1 million. (Staff Group Cross Ex. 1-B) The Companies' example does not support their "lender of last resort" argument.

Finally, the Ameren IB mistakenly states that upfront fees for the NiSource term

[7] As explained in Staff's Initial Brief at pages 98-99, amending and restating the 2006 and 2007 Illinois Facilities would have obliged "Declining Lenders" to provide loans at the lower rates in those agreements through their original terms (*i.e.*, January 2010). In contrast, replacing the 2006 and 2007 Illinois Facilities freed "Declining Lenders" from their obligation to provide loans at the 2006 and 2007 credit agreement rates. Ameren seems to be less concerned about minimizing the cost of capital of its Illinois utilities than its non-regulated companies.

[8] When asked why the Illinois Facility was not amended, like the Missouri Facility was, Mr. O'Bryan testified, "[t]here were no banks that declined the Illinois Facility and, therefore, there was no old facility that stayed in place." (Tr., p. 227, December 15, 2009) To the contrary, Mr. Nickloy identified Citibank and Wachovia as lenders under the AIUs' prior bank facilities. (Ameren Ex. 28.0, p. 6) Both of those lenders are "non-extending lenders" under the 2009 Illinois Facility. (Staff Ex. 19.0R, Attachment G)

loan (not credit facility as implied by the AIU) were 3.00%. (Ameren IB, pp. 140-141) In fact, the upfront fees for that term loan were 2.0%. (Staff Ex. 19.0R, Attachment E)

For all of the foregoing reasons, including the reasons provided in Staff's Initial Brief at pages 93-100, the Commission should reject Ameren's calculation and allocation of the AIU bank commitment fees. The Commission should adopt Staff's recommendation, which is consistent with Section 9-230 of the Act.

1. CILCO – Contested

The 2.15% short-term debt cost rate that Ameren maintains is appropriate for CILCO equals Staff's initial estimate. (Ameren IB, p. 146) Ameren's cost of short-term debt proposal for CILCO is lower than Staff's 2.50% proposal, which is based on Staff's estimate of CILCO's implied ratings from Moody's and S&P. (Staff Ex. 5.0R, pp. 7 and 14) As such, Staff does not oppose Ameren's recommendation for a 2.15% cost of short-term debt for CILCO.

Ameren argues, "Ms. Phipps' adjustment to AmerenCILCO's bank facility fee is unwarranted." (Ameren IB, p. 149) Staff's recommended bank facility fee for CILCO is based on CILCO's current Moody's secured credit rating (Baa1) and implied S&P secured credit rating, adjusted solely to reflect a lower degree of business risk (A). (Staff IB, p. 92)

Ameren argues that S&P assigns CILCO the same credit rating as CIPS and one notch better than IP, even though neither CIPS nor IP has an unregulated generation subsidiary. (Ameren IB, p. 147) S&P rating reports for the AIU confirm that S&P ratings are based on Ameren Corporation's consolidated credit profile. (Staff Ex. 19.0R, Attachments A-CILCO, A-CIPS and A-IP) That is, S&P considers all of the Ameren companies – regulated and non-regulated – a single entity when it assigns ratings. Because S&P ratings reflect non-regulated companies, those ratings cannot be relied upon for ratemaking purposes under Section 9-230 of the Act. S&P is very clear on how non-utility affiliates affect CILCO's ratings. S&P assigns CILCO a "Satisfactory" business profile and assigns CIPS and IP "Strong" business profiles. Therefore, Staff removed the effects of CILCO's non-utility affiliates by adjusting its credit rating to reflect utility operations only.

Finally, Ameren argues:

> …any adjustment based on an assumption that AmerenCILCO would be entitled to a higher rating is unfounded. Simply stated, Ms. Phipps cannot step into the shoes of the ratings agencies and reasonably opine that they credit ratings for AmerenCILCO would be any different than they are today if it no longer had an unregulated generation subsidiary and/or was no longer owned by an intermediate parent company. (Ameren IB, p. 148)

To the contrary, Ms. Phipps does not assume that CILCO is entitled to a higher rating. Rather, consistent with Section 9-230, Ms. Phipps assessed whether CILCO's non-utility affiliates increased the cost of capital for CILCO by reviewing CILCO's, CIPS and IP's rating reports by Moody's, S&P and Fitch Ratings. She adjusted nothing except CILCO's business profile score to measure the effects of non-utility affiliates on CILCO's cost of short-term debt and only after she thoroughly examined the Moody's and S&P rating methodologies. Finally, she revised CILCO's cost of short-term debt upward after Moody's revised its rating methodology in August 2009, which demonstrates that her adjustment to CILCO's business profile score is balanced and unbiased.

CILCO argues that Staff's Section 9-230 adjustment would be warranted only if the Commission is certain that the rating agencies would give CILCO a higher credit rating if it were not affiliated with CILCORP and AERG. This level of proof is absurd because it would require either an ability to observe a situation that does not exist (*i.e.*, CILCO sans non-utility operations) or rating agency reports that are based on hypothetical situations (*i.e.,* CILCO sans non-utility operations). Applying CILCO's logic to the ratemaking process would be inconsistent with the Act's requirement that the Commission remove every iota of an increase in the cost of capital due to a utility's affiliation with non-utilities because it is impossible to prove with certainty what does not exist. Rather, to comply with Section 9-230 of the Act, the Commission must consider expert opinion regarding the cost of capital consequences of actions that cannot be observed. For all the foregoing reasons, the Commission should adopt Staff's recommended bank facility fees for CILCO.

2. CIPS – Resolved

3. IP – Resolved

F. Cost of Common Equity

1. Resolved Issues

2. Contested Issues

a. Return on Equity Estimates

b. DCF and CAPM Model Issues

c. Growth Rates

Ameren argues that Ms. Freetly's use of the non-constant DCF is a departure from Staff's typical use of the constant growth DCF and points out that Staff relied on the constant growth DCF model in previous testimony when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. (Ameren IB, pp. 154-155) Ameren's argument implies that Staff cannot modify its methodology even when a revised methodology more accurately reflects existing circumstances, and is likely to yield more reliable results. Ameren's argument would have a modicum of validity if Staff did not present its rationale with supporting analysis, as it has done convincingly here.

Ms. Freetly testified that a single-stage constant growth DCF model employs a single growth rate estimate, which is assumed to be sustainable infinitely. Thus, the cost of common equity calculation derived from a constant growth estimate is correct only if the near-term growth rate forecast for each company in the sample is expected to equal its average long-term dividend growth. In theory, no company could sustain into infinity a growth rate any greater than that of the overall economy. Given the difference between the growth rates for the Gas and Electric samples and the overall growth of the economy, the continuous sustainability of the analyst growth rates for the Gas and Electric samples is highly unlikely. Thus, Staff implemented a multi-stage, non-constant growth DCF model. (Staff Ex. 6.0, pp. 5-6)

Inclusion of the constant growth DCF analysis cannot be reconciled with the compelling rationale for employing the non-constant DCF analysis, namely that the 3-5 year analyst growth rates are unsustainable, as Staff has explained in detail. (Staff IB, p. 118) The decision as to which model to employ must be consistent with the judgment regarding the sustainability of the growth rate to be used in the model. The Commission noted as much in the Order of a previous Illinois American Water Company ("IAWC") rate proceeding:

> It appears to the Commission that the reasonableness of the growth rates, how the growth rates are developed, and what

> version of the DCF model should be used are interrelated in this case.[9]

In that proceeding, the Commission rejected IAWC's constant growth DCF analysis on the basis that the growth rates were unsustainable into perpetuity and, instead, relied exclusively on non-constant DCF analyses.[10] Likewise, the Commission should reject Ms. McShane's constant growth DCF analysis in this proceeding.

The Company states that Staff's long-term growth rate used in the final stage of the non-constant DCF analysis based on the implied 20-year forward U.S. Treasury rate is inferior to the estimate of long-term economic growth provided by the consensus of economists' forecasts published by Blue Chip because (1) it is more appropriate to use a direct estimate of long-term economic growth as provided by the consensus of a large sample of economists' forecasts; and (2) long-term growth expectations should be more stable than U.S. Treasury bond yields. (Ameren IB, p. 156)

The Company's argument regarding the use of a direct estimate of long-term economic growth ignores Ms. Freetly's testimony that she compared her 4.83% U.S. Treasury bond-derived estimate of long-term growth against the 4.5% forecast of Global Insight. While Staff agrees that having a consensus forecast of long-term economic growth for a period that <u>begins</u> ten-years from now, the record contains nothing to suggest that any exists; the Blue Chip forecast that the Companies espouses covers a period that <u>ends</u> ten years into the future.

The Company's argument concerning the alleged stable nature of long-term growth forecasts aims at one target, Staff's long-term growth estimate, but hits another, the constant growth DCF. According to Ms. McShane, the long-term growth rate should

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[9] Order, Docket No. 07-0507, July 30, 2008, p. 90.
[10] Order, Docket No. 07-0507, July 30, 2008, p. 92.

be stable. (Ameren Ex. 36.0, pp. 4-5) The constant growth DCF assumes that short-term growth equals long-term growth. Thus, according to Ms. McShane's argument, the growth rates used in the constant growth DCF should be stable. The evidence proves that the growth rates Ms. McShane uses in her constant growth DCF analysis are anything but. In the last rate case proceedings for the AIU, Docket Nos. 07-0585 – 07-0590 (Cons.),[11] Ms. McShane's constant growth DCF analysis used IBES growth rate forecasts. In the 2007 rate cases, the IBES growth rate for the gas companies common to the 2007 and current cases averaged 4.6%. In comparison, in the current proceeding, the IBES growth rate for the gas utilities in common to the 2007 and current cases averaged 5.7%. Four of the seven gas companies that were part of the Gas sample used in both 2007 and the current cases changed by more than one percentage point. Many of the electric companies common to the 2007 and current cases also exhibit some large differences in the IBES growth rate forecasts. For example, the IBES growth rate for Integrys Energy changed from 6.3% in 2007 to 26.2% in 2009,[12] a difference of 19.9%. Moreover, 13 of the 24 electric companies that were part of the Electric sample in both 2007 and 2009 changed by more than two percentage points. (Staff Group Cross Ex. 1 – N 07-0585 CILCO Ex. 7.0G) Those large differences indicate the IBES growth rates are not stable, which according to the Company, disqualifies the IBES growth rates from being considered as long-term growth rates. Since the IBES growth rates cannot be used as long-term growth rates, they cannot be used in a constant-growth DCF model, which, as discussed above, assumes the short and long-term growth rates are equal. In summary, the large difference in IBES growth

[11] Hereafter referred to as the "2007 rate cases."

[12] Amazingly, nothing in Ms. McShane's testimony suggests she finds anything improbable in a long-term growth rate of 26.2%.

rates indicates the results of the constant growth DCF should not be considered in determining the investor required rate of return on common equity for setting rates in this proceeding.

Regardless of the alleged instability of U.S. Treasury bond yields, the Blue Chip forecast utilized by Ms. McShane has severe shortcomings as an estimate of long-term growth beginning ten years from now. First, the Blue Chip forecast does not coincide with the period of time that the final stage of the non-constant DCF covers (year 11 and beyond). (Staff IB, p. 119) To the contrary, the Blue Chip forecast covers only the first ten years of growth, that being, the short and transition growth stages. In contrast, Staff's implied 20-year forward U.S. Treasury rate estimates the rate of economic growth for years 11 and beyond and is therefore a better estimate of investor expectations for the final stage of the non-constant DCF analysis. In addition, Staff's 4.83% implied 20-year forward Treasury rate in ten years is supported by Global Insight's forecast of 4.5% nominal GDP growth for the 2019-2039 period. (Staff Ex. 6.0, p. 8)

Second, there is no valid justification for disregarding the investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. It is important to note that T-bond yields directly reflect the expectations of investors, while Blue Chip forecasts do not. That is, investors' buy and sell decisions set the T-bond yield, thereby revealing their expectations, whereas Blue Chip forecasts merely reflect the opinions of a limited number of analysts, made with no direct financial interest in the yields they are predicting. Thus, the forecasts Ms. McShane advocates are merely proxies for investor expectations. Proxies are a source of measurement error in cost of common equity estimation. Therefore, proxies should be used only when the market factor in question is not observable. Since market expectations for T-bond yields are observable, proxies for those expectations, such as a Blue Chip forecast, should not be used. Moreover, the current U.S. Treasury yields Ms. Freetly used to measure GDP growth reflect all relevant, publicly-available information. Consequently, any influence Blue Chip forecasts might have on investor expectations is already reflected in the current U.S. Treasury yields.

Further investigation of the Blue Chip Financial Forecasts relied on by Ms. McShane to estimate the long-term economic growth reveals that the forecast did not include the recessionary period in 2009 and 2010. The first five years of the forecast that she utilized reflect recovery from the recession, which inflates long-term sustainable growth in real GDP over the 2011-2015 time period. The consensus growth forecasts for 2009 and 2010 are 1.2% and 4.1% respectively, compared to 5.0% for 2011-2015 used by Ms. McShane. (Staff Group Cross Ex. 1 – M Blue Chip Financial Forecasts) When using a forecasted growth rate for the economy, the whole business cycle must be included in order to get a measure of the normal steady state rate of growth that can reasonably be expected over the long-term.

d. Beta

Ameren argues to exclude Staff's beta estimates derived using monthly data. Ms. McShane claims that weekly betas are more reliable because more data points are employed and are thereby less likely to be impacted by outlying observations. (Ameren IB, p. 165) As Staff has demonstrated, however, the statistics presented by Ms.

McShane do not establish the superiority of weekly betas to monthly betas. (Staff IB, pp. 121-122) While Ms. McShane's analysis showed that weekly betas generally have a lower standard error than monthly betas, which indicates that weekly betas are usually more reliable than monthly betas, Ms. Freetly's analysis showed that the coefficient of variation was higher for weekly data, which indicates that there is an increase in random error due to higher volatility per mean return. (*Id.*, p. 125) The higher coefficient of variation for the weekly betas is not a function of the higher weekly betas, as Ms. McShane claims. (Ameren IB, p. 165) Ms. McShane's argument implies that the risk of a stock is a function of the measurement period of its return. This in turn has two possible implications: (1) a company's stock is riskier than itself; and (2) the shorter the holding period of the stock, the more risky it is. Alternative (1) is obviously a ridiculous proposition since a security cannot be riskier than itself. While alternative (2) is plausible, it invites the question of why the Commission should assume that the typical holding period for a utility common stock is only one week. Fortunately, the Commission need not determine the typical holding period for a utility common stock because the coefficient of variation actually indicates that there is more noise in the weekly data which reduces the accuracy of the weekly betas, regardless of cause.

In addition, Staff's analysis of the lag beta indicates that non-synchronous trading, or the lag in stock price reaction to economic events that affect the market, was a problem when using weekly data but not when using monthly data. The one and two week lags for Ms. McShane's weekly data for the Gas sample are -0.07 and -0.11, respectively, which results in a sum beta of 0.42. (Staff IB, p. 124) The adjusted sum beta equals 0.61.[13] This weekly adjusted sum beta equals Staff's beta estimate of 0.61, which was derived by taking the average of the weekly and monthly beta estimates. (*Id.*, p. 105) Hence, when the weekly beta is adjusted for the lags in stock price reaction to economic events that affect the market, the beta for the Gas sample is the same as Staff's average beta estimate. Since neither type of beta is clearly superior to the other, the Commission should equally weight weekly and monthly betas in determining a cost of common equity with the CAPM. (*Id.*, pp. 125-126)

e. Market Risk Premium

(1) Risk-free Rate

The AIUs maintain that the "spot" interest rates are not appropriate for application of the CAPM since a forward looking estimate of the cost of equity should recognize the high probability that U.S. Treasury yields will increase. (Ameren IB, p. 176) The current U.S. Treasury yields that Staff used as the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. (Staff IB, p. 126) The true risk-free rate is reflected in the return investors are willing to accept in the market. As of August 18, 2009, investors were willing to accept a 4.40% return on T-bonds.[14] (*Id.*, p. 105) Further, as explained above, it is critical to synchronize the data inputs used in a cost of equity analysis so that all inputs reflect expectations as of the same time.[15] There is no valid justification for disregarding the

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[13] Staff presented the equation that Value Line uses to adjust the beta estimate in its direct testimony. (Staff Ex. 6.0, p. 19)

[14] Five months later, on January 20, 2010, U.S. Treasury bond yields are only 14 basis points higher, at 4.54%, which indicates that 30-year "spot" interest rates are not particularly volatile. (http://www.federalreserve.gov/releases/h15/update/)

[15] Similar to the issue of single-issue ratemaking, an analyst cannot selectively update components of a cost of common equity analysis, since the circumstances that cause one input to change

investor expectations directly reflected in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. No one can forecast with any certainty the timing, direction, or magnitude of long-term interest rate changes.

Further, it should not be forgotten that Ameren chose to initiate this proceeding during a severe economic recession when undoubtedly a large segment of its customer base is suffering financially. In response to this severe economic downturn, interest rates have fallen. Staff's recommended cost of common equity reflects that economic reality. In contrast, Ameren would have the Commission reward Ameren's decision to file a rate case during a severe economic recession with a rate increase that assumes that Ameren filed its requested rate increase during a far more favorable economic environment. That is appalling.

(2) Return on the Market

IIEC witness Mr. Gorman testified that Staff's market risk premium in its CAPM analysis is overstated. (IIEC IB, pp. 58-59) Staff recognized that some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate, and, thus in Staff's CAPM cost of equity estimate. (Staff IB, p. 119) Although there is upward bias in Staff's estimate of the market return, there is no way to know the extent of the bias. Staff did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate model to 500 companies. Mr.

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would likely influence the other inputs, as well. Thus, if one input is to be updated, the entire analysis must be updated. Otherwise, the result is an uninformative hodgepodge of mismatched data inputs reflecting different sets of investor expectations rather than a true cost of common equity that consistently represents investor expectations at a given time.

Gorman's non-constant DCF analysis of the S&P 500 illustrates the difficulty of applying that model to the diverse group of companies that compose that index. Mr. Gorman's estimate of the required return of the market is 8.71%, which is 129 basis points below his 10.00% rate of return on common equity recommendation for the AIU. His results imply that the S&P 500 is less risky than the AIU, which is not plausible. (*Id.*, pp. 118-119)

f. Proposed Adjustments

(1) Financial Risk

Staff and the Companies agree that when a utility has more or less financial risk than the sample companies used to estimate the cost of equity, an adjustment to the cost of equity is necessary. (Ameren IB, p. 178) Ms. McShane asserts that when the market value common equity ratio is higher than the book value common equity ratio, the market is attributing less financial risk to the companies than the book value capital structure suggests. She claims that since the investor required rate of return is estimated based on the market value of the companies in the Gas and Electric samples, adjustments to recognize the higher financial risk implied by the book value capital structure of the AIU is required. (*Id.*, pp. 179-180)

Staff maintains that there is no merit to Ms. McShane's claim. The fundamental problem with Ms. McShane's claim is that it assumes, without foundation, that the book value capital structure of the AIU directly reflects investors' perceptions of the financial risk of the AIU. Of course, investors are unlikely to ignore the book value capital structure of companies generally and utilities specifically. Nevertheless, investors' perceptions of AIU's financial risk inherent in its book value capital structure are not observable because its common stock is not market traded. Thus, Ms. McShane's argument is meritless. The Commission should disregard Ms. McShane's market to book adjustments as it has done in previous rate proceedings. (Staff IB, pp. 115 -116)

AIU argues that Ms. Freetly's adjustments are incorrect because they are based on the assumption that the AIU will achieve the credit metrics implicit in Staff's recommendations. (Ameren IB, p. 182) The Commission will set just and reasonable rates for the natural gas distribution and electric delivery service operations of the AIU in this proceeding. The Staff recommendations reflect the revenue requirements necessary to set just and reasonable rates, which will remain in effect until a future rate proceeding. Ms. Freetly used Staff's recommendations to estimate the credit metrics that may be achieved with the just and reasonable rates set in this proceeding.

However, Staff's analysis of the implied level of financial strength of the gas and electric utility operations of each of the AIU is not an attempt to predict the rating outcome of Staff's position in these rate proceedings. Staff did not attempt to determine its own credit ratings for the AIU nor is Staff suggesting that simply because the Companies' metrics fall within the guideline ranges that the implied ratings will result. Rather, Staff performed the ratio analysis in order to compare the financial strength of the Companies, based on the FFO to interest coverage, FFO to total debt, DCF to total debt coverage and debt to capitalization, to those of the Gas and Electric samples. The resulting ratios were translated into implied credit ratings only to have a metric on which to base an adjustment to the cost of equity. Corporate debt yields are published by credit rating, not financial ratio. Ratio analysis is necessary to evaluate the riskiness of the AIU's gas and electric operations versus proxy samples. (Staff Ex. 20.0, pp. 11-12)

The credit rating agencies evaluate the legal entity level and do not develop separate credit ratings for a company's business segments. Therefore, if Ms. Freetly had been developing credit ratings for the AIU, she would have performed a single financial strength analysis for each company that would have reflected the combined financial strength of each company's business segments, including electric transmission. Further, Staff would have recommended adjustments to the Companies' variable rate debt to reflect the cost associated with the "predicted credit rating." (***Id.***, p. 12)

Staff did not use the current credit ratings of CILCO, CIPS and IP for comparison to the Gas and Electric samples for several reasons. First, credit ratings reflect the risk of a company's entire operations, not just those operations subject to the Commission's rate jurisdiction. Second, credit ratings also reflect a company's affiliation with other companies. Section 9-230 of the Illinois Public Utilities Act prohibits including in a utility's allowed rate of return any incremental risk or increased cost of capital which is the direct or indirect result of a public utility's affiliation with unregulated or nonutility companies. (220 ILCS 5/9-230) Hence, Section 9-230 prohibits relying on such ratings when assessing the risk of a utility's operations. Third, credit ratings reflect the credit ratings agency's forecast. Since those forecasts are not published, they cannot be compared to Staff's revenue requirement recommendations. For all these reasons, the Companies' credit ratings should not be relied upon absent an investigation of the underlying standalone, going forward strength of the Companies. (Staff Ex. 20.0, pp. 12-13)

The AIUs claim that Staff's financial risk adjustment incorrectly assumes that equity investors quantify financial risk differences in the same manner as bond investors. (Ameren IB, p. 182) Although Staff agrees that bond and common equity investors would not likely apply the same price to a given difference in financial risk, the price the latter would attach to financial risk cannot be observed. Therefore, a proxy is necessary. The bond yield spreads that Staff's adjustment is based on are the best estimate of the different return requirements that investors would demand for varying levels of financial risk. Hence, it is an objective measure of the return equity investors would require to invest in the AIU given the different levels of financial risk indicated by Staff's ratio analysis.

(2) Fixed Customer Charge

Staff's cost of common equity recommendation includes the same 10 basis point adjustment to the cost of common equity for the AIU gas companies that the Commission found appropriate in the last rate cases to reflect the reduction in risk provided by the move to more fixed cost recovery. (Staff IB, pp. 131-132) Ms. Freetly recognized that most of the companies in the Gas sample have in place some sort of decoupling mechanism, but some of those mechanisms are only applicable to a portion of the company's service territories, and one of the companies has no decoupling mechanism at all. Thus, a small cost of equity adjustment for the reduction in risk provided by the move toward more fixed cost recovery is warranted, and the 10 basis point downward adjustment adopted in the Companies' last rate case is appropriate in this proceeding, (*Id.*, p. 132)

(3) Uncollectibles Riders

Ameren claims that Staff's approaches to estimate adjustments to the costs of common equity for the gas and electric operations of the AIUs to reflect the reduced risk that would result from the AIUs being allowed to recover uncollectibles via an uncollectibles rider are flawed and should be rejected. (Ameren IB, p. 186) As Ms. Freetly acknowledged, Staff is unaware of any established approach for precisely gauging the effect the adoption of the uncollectibles riders would have on investors' perceptions of the Companies' risk levels and the resulting costs of equity. Thus, any adjustment will inevitably be inexact. (Staff IB, p. 134)

The uncollectibles riders would ensure more timely and certain collection of bad debt expenses, thereby reducing the uncertainty of cash flows, which would reduce the Companies' risk. The reduction in risk must be recognized with downward adjustments to the authorized rates of return. Staff's approaches reflect a range of alternatives to gauge the resulting risk reduction associated with this cost recovery mechanism.

Staff's first approach is based on the spread for a one notch upgrade to the credit ratings implied by the financial ratios for the AIUs. Since the adoption of the uncollectibles riders would enhance the utility's ability to recover costs and earn returns, a utility's score on this factor of the Moody's rating methodology would improve. Although Moody's recognized the passage of the bad debt rider legislation when upgrading the ratings of the AIUs to investment grade, this will only affect the cost of future AIU debt. The effect the rider will have on AIUs' costs of common equity must still be estimated. The Moody's based adjustments should be considered the minimum adjustment that is required to recognize the reduction in risk. Debt is less exposed to revenue variability since equity partially shields debt from that variability. (Tr., p. 279, December 15, 2009) Hence, this cost recovery mechanism affects the Companies' common equity more than their debt. Consequently, this adjustment based on the implied credit ratings is the absolute floor of Staff's recommendation for adjustment to the cost of common equity.

Staff's second approach is tied to the uncollectible experience of the AIUs. Based on the data provided by Ameren, the Companies have been under recovering uncollectible expenses. Hence, the uncollectible riders will allow the Companies to collect additional revenue associated with uncollectible expenses. Ms. Freetly's adjustments are based on the specific amount of under recovery experienced by each of the Companies.

Ameren claims that Ms. Freetly assumes that the actual return on equity rises toward the allowed return and the cost of equity falls by an equivalent amount. Ms. Freetly's adjustments for the uncollectibles riders are based on financial theory, which posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Since the riders remove the uncertainty associated with the recovery of uncollectibles and reduce risk, Riders GUA and EUA also reduce the investor-required rate of return.

Ameren claims that the AIU have higher business risk than the sample utilities before the adoption of the riders, which suggests that the implicit point of departure for the rider adjustments is wrong and the downward adjustments are not supportable. (Ameren IB, p. 188) Staff selected the same gas sample as Ameren witness McShane. Further, Staff adopted Ms. McShane's electric sample with the exception of Companies the Edison Electric Institute deemed to be "Mostly Regulated." This is the same selection methodology with which the Commission set the Companies' cost of common equity in the 2007 rate cases.[16] Since that time, Moody's noted an improved political and regulatory climate in Illinois. (Staff Ex. 6.0, p. 39) Thus, between 2007 and 2009, the AIU operating risk has declined and yet, if the Company is to be believed, since 2007, the Companies have become riskier than their own witness' samples. Further, it is more than odd that the Companies did not notice the alleged disparity in risk between its own witness' samples and the AIU until the Surrebuttal stage, when Staff had no further opportunity to respond. Until that point in time, both Ms. McShane and Staff assumed that the Gas and Electric sample companies had similar business risk to the AIU gas and electric operations, respectively, since they operate in the same industries.

In her Surrebuttal testimony, Ms. McShane states:

> The implied ratings for Regulatory Framework and Ability to Recover Costs and Earn Returns assigned to the Ameren Utilities, to which Moody's gives 50% weight in assigning ratings, are Ba and Baa respectively. The corresponding median ratings for the 21 U.S. utilities (gas and electric) reviewed in Moody's August 2009 Rating Methodology: Regulated Electric and Gas Utilities are Baa and A respectively. While the utilities for which Moody's reports the ratings include some which are in Ms. Freetly's proxy samples and some which are not, the fact is that a relatively broad sample of gas and electric utilities has higher implied credit ratings on these two factors than the Ameren Utilities, i.e., of lower business risk. That evidence strongly suggests that Ms. Freetly's implicit point of departure (similar business risk) for making her downward adjustments is incorrect and thus the downward adjustments she proposed for the uncollectibles riders based on credit ratings are not supportable." (Ameren Ex. 52, p. 21)

By looking at only two factors of several that Moody's considers in determining the operating risk of the utilities that it rates, Ms. McShane draws a conclusion on how

[16] Order, Docket Nos. 07-0585 – 07-0590 (Cons.), September 24, 2008, pp. 179 and 216.

the AIU compare to the other companies in the Moody's report. From that observation, she then makes the leap that the AIU are riskier than the Gas and Electric samples with two unsubstantiated assumptions. First, she assumes that the Gas and Electric samples are the same as the companies in the Moody's report, which directly contradicts her statement that "some" of companies in the report are not in Ms. Freetly's samples. (Ms. McShane does not even bother to identify the number of companies in the report that are in her electric and gas samples, let alone their identities. We do not even know whether the number of companies in the report constitute a majority of the companies in the gas and electric samples.) We do not know how the companies in the sample that are not included in the report compare to the AIU on that 50% of Moody's credit rating assessment (i.e., "Regulatory Framework and Ability to Recover Costs and Earn Returns"). Second, Ms. McShane assumes that those are the only factors that Moody's considers to determine operating risk, which was not established in this proceeding.

Ameren also points out the Ms. Freetly testified that the implied financial risk of CILCO Gas and IP Gas are the same, yet her proposed adjustments for the uncollectibles rider are not the same. The financial risk comparison reflects the operating income of each of the Companies prior to the adoption of the uncollectibles riders. The comparison of Staff's financial risk adjustment and Staff's adjustment for the uncollectibles riders is not valid. The uncollectibles rider adjustment affects operating risk, not financial risk. The operating income analysis recognizes the effect of the adoption of the uncollectibles riders and is based on the under-recovery experienced by each of the Companies over the last ten years. The uncollectibles data shows that the affect of Rider GUA on CILCO Gas would be greater than IP Gas given the fact that uncollectibles is a much higher percentage of CILCO Gas' operating income.

g. Other

G. Recommended Overall Rate of Return

1. CILCO Electric

As summarized in Staff's Initial Brief and further supported herein, Staff recommends an 8.28% rate of return on rate base for CILCO's electric delivery services, which reflects a 10.38% rate of return on common equity for CILCO's electric operations. (Staff IB, p. 143)

2. CIPS Electric

The Ameren IB errs when it refers to CIPS Electric "Weighted Average Cost of Capital as of 3/31/2009." (Ameren IB, p. 190) The uncontested capital structure measurement date for CIPS Electric is December 31, 2008. (Ameren Ex. 37.1, p. 2; Staff IB, p. 144)

As summarized in Staff's Initial Brief and further supported herein, Staff recommends an 8.06% rate of return on rate base for CIPS' electric delivery services, which reflects a 10.14% rate of return on common equity for CIPS' electric operations. (*Id.*, p. 144)

3. IP Electric

As summarized in Staff's Initial Brief and further supported herein, Staff recommends a 9.05% rate of return on rate base for IP's electric delivery services, which reflects a 10.44% rate of return on common equity for IP's electric operations. (*Id.*, p. 144)

4. CILCO Gas

As summarized in Staff's Initial Brief and further supported herein, Staff recommends a 7.95% rate of return on rate base for CILCO's gas delivery services, which reflects a 9.64% rate of return on common equity for CILCO's gas operations. (*Id.*, p. 145)

5. CIPS Gas

The Ameren IB errs when it refers to CIPS Gas "Weighted Average Cost of Capital as of 3/31/2009." (Ameren IB, p. 191) The uncontested capital structure measurement date for CIPS Gas is December 31, 2008. (Ameren Ex. 37.1, p. 2; Staff IB, p. 145)

As summarized in Staff's Initial Brief and further supported herein, Staff recommends a 7.69% rate of return on rate base for CIPS' gas delivery services, which reflects a 9.38% rate of return on common equity for CIPS' gas operations. (*Id.*, p. 145)

6. IP Gas

As summarized in Staff's Initial Brief and further supported herein, Staff recommends an 8.70% rate of return on rate base for IP's gas delivery services, which reflects a 9.64% rate of return on common equity for IP's gas operations. (*Id.*, p. 146)

V. PROPOSED RIDERS

A. Overview

B. Resolved Issues

1. Revisions to Rider S for PGA Uncollectibles

2. Exclusion of Electric Distribution Tax/Public Utilities Revenue Act Tax from Tax Additions Rider

C. Contested Issues

1. Rider VGP

The AIU discussion of Rider VGP only serves to further Staff's position that the program is not sufficiently designed (or explained) for Staff to recommend approval at this time. The language of "planned approach," "still attempting to determine," "must be cautious," and "flexibility" are in conflict with the AIU's belief that there might be stable REC prices. (Ameren IB, pp. 195-196) While the AIU plan to provide reports on Rider VGP activity (*Id.*, p. 197), that does nothing to relieve Staff's concern that the plan has not been sufficiently developed for the Commission's consideration at this time. If the AIU are not yet able to clearly define and present their proposal to the Commission, the Commission should be concerned that the Ameren customers, to whom this plan will be marketed, might not have a clear understanding of exactly what would be bought. For these reasons, Staff is unable to recommend approval of the proposed Rider VGP.

VI. COST OF SERVICE/REVENUE ALLOCATION

A. Overview

B. Resolved Issues

1. Gas/Electric

2. Electric

3. Gas

a. Weather normalization

b. Billing determinants

c. Rate Classes

C. Contested Issues

1. Electric

a. AIUs' Cost of Service Studies

One general cost of service argument by the Companies should be readily dismissed by the Commission. That is the implication that their cost of service arguments should receive more credence because they "are the only parties to offer a cost of service study based upon its own model" in this case. (Ameren IB, p. 204) In contrast, they indicate that Staff and the IIEC do not offer studies of their own, but rather make revisions to the AIUs' studies. (*Id.*) This argument should be disregarded by the Commission. The utilities are the source of cost of service studies because it is their overall costs that are being allocated among customer classes. Furthermore, they are required to provide such studies under Part 285. Nevertheless, there is no guarantee that their studies are accurate. For example, it should be noted that the AIUs propose to change the allocation of distribution taxes in this case as a delayed reaction to legislation passed in 1997. Thus, their action in this case is to correct an inappropriate allocator from previous cases. They have also accepted a revised allocator for Account 362, substations, during the hearing process. (*Id.*, p. 207)

These are not the only shortcomings with their cost of service studies as Staff has shown with regard to the allocation of primary lines and substations costs. Each cost of service argument should be assessed on its own merits and the fact that the AIUs furnished the original cost study for this case should not influence the Commission's decision on this issue in any manner. (Staff Ex. 7.0, pp. 5-9)

b. Allocation of Costs to Customers Receiving Service at Voltages 100+ Kv

c. Allocation of Cost of Primary Distribution Lines and Substations

The arguments by the AIUs for their proposed NCP allocator over Staff's CP approach present problems and should be rejected by the Commission.

The Companies begin citing precedent for these costs, noting that the NCP has been approved by the Commission in previous AIU rate cases. (Ameren IB, p. 212) Their claim is certainly true but the fact that the NCP has been used previously does not demonstrate that it is the more cost-based alternative in this case.

Their argument with respect to costs is perfunctory and incomplete. The AIUs simply assert without explanation that the NCP offers the further advantage of being cost-based. As Staff has shown, that assertion is not support by the evidence in this case. (Staff Ex. 7.0, pp. 5-9)

The AIUs then focus their attention on discussion of Staff's CP alternative. After noting that Staff's proposed CP allocator represents the collective demands of multiple rate classes, they appear to undermine their own argument by stating that "the AIUs' facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes." (Ameren IB, pp. 212-213) This acknowledgement by the Companies is critical because facilities that service multiple rate classes should be allocated according to the collective peak demands of multiple peak demands (the CP approach) rather than by individual class demands (the NCP approach).

Nevertheless, the Companies claim that the CP allocator is inappropriate because CP demand "is always less than the sum of the localized demands placed on distribution facilities." The AIUs contend that "[l]ocal facilities such as substations and primary lines are not built and sized with this level of diversity in mind." Instead, they argue that distribution system planners "look at the expected peak of customers connected to the facilities, whether they occur in summer, fall, winter, or spring." The AIUs conclude by asserting that "[t]he NCP demand more closely matches the load diversity on these more localized system [sic.]" (*Id.*, p. 213)

It is certainly true that the CP is not an exact fit for allocating primary lines and substations since the CP is calculated on a systemwide basis, while this equipment is sized to meet local demands. Nevertheless, the NCP is calculated on a systemwide basis as well and thereby does not reflect localized demands either. In other respects, the CP is clearly better since, as the Companies admit, primary lines and substations are sized to meet the demands of "customers in multiple rate classes." (Staff Ex. 21.0, p. 6)

In addition, the AIUs lack any evidence for their assertion that NCP demand more closely matches the load diversity on these more localized systems. This is self-evident considering that primary lines and substations serve many classes at one time while the NCP measures individual class demands separately. (*Id.*)

The Companies then present an argument on this issue that should not belong in a discussion of cost allocation. The argument focuses on results, stating that the CP approach "would not be beneficial to many of the AIUs' customers." The AIUs then identify which classes in all three Companies would benefit and which would suffer under a CP approach. (Ameren IB, p. 213)

This customer impacts argument is clearly misplaced. A cost of service study should allocate costs solely based on how classes cause those costs to be incurred. Only after costs are allocated and class revenue responsibility is determined is it appropriate to consider bill impacts in the ratemaking process. Injecting bill impacts into the cost allocation process makes it impossible to determine the real responsibility of customer classes for system costs. As a result, it will be that much more difficult to make an informed decision concerning the appropriate balance of costs and bill impacts in the ratemaking process.

The Companies also focus on the role of lighting customers in the discussion. They begin by stating that "Staff further contends that lighting customers should not bear any costs with substations or primary lines, since they are peak during off-peak, evening hours, and states that peak lighting loads should play a lesser role in determining the size of primary distribution lines and substations." (*Id.*) The problem, according to the Companies, is that the CP would allocate "zero costs" for substations and primary lines to lighting customers even though they use these assets. (*Id.*, pp. 213-214)

Again, the issue here concerns causation of these costs and what the allocation classes receive should reflect their contribution to these costs. If lighting customers use electricity when other classes use less, their demands will not drive the causation of these costs. What the Companies leave unsaid is that the NCP allocates primary line and substation costs to lighting customers based on their maximum demands which occur during off-peak hours. It is patently unfair to give as much weight to these off-peak demands as for maximum demands by other classes that do coincide with the peak. Clearly, it is these latter demands, not lighting demands, that drive primary line and substation investments. (Staff Ex. 7.0, p. 8)

The Companies further seek to defend their approach by arguing that "the use of NCP does not 'punish' non-weather-sensitive customers, as Staff contends." They insist that "[i]nstead, it appropriately allocates the cost of facilities to match how the facilities were designed, built, and sized." (Ameren IB, p. 214) What is lacking from this argument is any explanation of how or why the NCP appropriately allocates these costs.

The Companies' argument cannot obscure the fact that the CP based on collective demands is the most appropriate allocator for a set of facilities shared by multiple rate classes. An NCP allocator based on maximum demands of individual rate classes clearly does not fit for facilities shared by multiple rate classes.

d. Allocation of Electric Distribution Tax/Public Utilities Revenue Act Tax

The IIEC's arguments for allocating distribution taxes by plant in service, rather than usage, are flawed and should be rejected by the Commission.

The IIEC begins its discussion by noting that the Legislature changed the method of recovering these taxes "[i]n conjunction with [the] Electric Service Customer Choice and Rate Relief Law of 1997." (IIEC IB, p. 70) The IIEC further indicates that "[t]he PURA Tax tier levels and the rates were custom-designed to collect approximately the same level of tax revenue from each utility, and in total, as the utilities paid previously, based on invested capital." (*Id.*) The IIEC also indicates that traditionally these costs were allocated among rate classes based on their share of plant in service. (IIEC IB, p. 71) The IIEC goes on to complain that the AIUs' proposal to allocate these costs on a usage basis "would have the effect of shifting millions of dollars of revenue responsibility, from the smaller customer classes to the large customer classes." (*Id.*)

IIEC presents a number of arguments against this proposed change. First, the IIEC claims the Company has failed to provide sufficient evidence to support a per-kWh allocation. Second, the IIEC claims that the current plant allocator reflects cost causation because "test year PURA [distribution] Tax responsibility of the Ameren Companies is based primarily on the invested capital tax levels in 1997, which were based on the utilities plant in service levels at that time." Third, the IIEC argues that "the assertions of Ameren and Staff that a utility's PURA Tax expense is purely or clearly a function of kWh sales ignores the history of the tax, the several other factors that affect the tax levels and the undisputed evidence in the record that PURA Tax responsibility for Ameren is not even well correlated to its kWh sales." The IIEC's fourth argument is that "the Illinois Legislature indicated in the 1997 Deregulation Law that it was interested only in "maintaining a comparable allocation among electric utilities in the State for payment of [PURA] taxes." The IIEC goes on to contend that the Legislature "did not give any indication that in modifying the collection structure, it intended to have the Commission shift cost burdens among customer classes." (*Id.*, pp. 72-72)

The IIEC's arguments are erroneous. First, and most importantly, there can be no doubt about the legislature's objective for this tax. The 1997 law states the clear intent "to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State." The Act goes on to state that in the General Assembly's view, this usage-based approach is "fairer and more equitable." (35 ILCS 620/1a, P. 90-561, eff. 1-1-98) In fact, it could be argued that a continued allocation of these costs by the plant in service method which the General Assembly explicitly rejected would directly conflict with the intent of the law. (Staff Ex. 21.0, p. 4)

The IIEC is also incorrect in suggesting that distribution (or PURA) taxes are correlated with plant, rather than sales. In fact, plant in service is no longer considered in the calculation of this tax. So, if the level of plant were to double or to decline by half, that specific change would have no impact on the utility's distribution tax. In contrast, the level of deliveries by electric utilities does directly affect distribution taxes. If a utility's level of deliveries goes up relative to other electric utilities in Illinois, its share of distribution taxes will increase. If its relative level of deliveries decline, the utility's share of the distribution tax total will fall. Clearly, usage is the driver now. (Staff Ex. 21.0, p. 5)

As far as whether the case for a usage-based allocator has been made, the weight of evidence in this proceeding has clearly fallen on the side of a usage-based allocator for these costs.

e. NCP Class Demands

f. Other

2. Gas

a. Account 904

As the Companies stated in their Initial Brief, Staff identified inconsistencies in the Cost of Service Studies (COSS) for the Uncollectible Expenses, Account 904. (Ameren IB, p. 217) The Company had used the exact same Account 904 amount for all three COSS. On October 22, 2009, the Companies provided updated COSS for AmerenCIPS and AmerenCILCO that corrected the net write-offs recorded in Account 904. Staff, inadvertently, did not address this issue on the record previously, but agrees with the corrections provided by the Companies to the COSS. Staff, also, agrees with

AIU that the results of the updated COSS should be factored into the final rate design approved by the Commission.

b. Storage Cost Allocations between Sales and Transportation Customers

Ameren set out to allocate storage costs to transportation, "based on the transportation customers' actual peak day usage during the historic test year," and "based on their ability to withdraw gas from their transportation banks on a peak day," which are not the same thing. (Ameren IB, p. 218) When Staff pointed out that its method did not accomplish what it set out to do, Ameren changed not the *method,* but the reason. (Staff Ex. 27.0R, pp. 36-37) From these two reasons, Ameren moves to a third reason: that 20 percent of usage (an amount in excess of tariff limits on withdrawals) represents "expected bank withdrawals" on a design day. (Ameren IB, p. 220)

Ameren makes the case that it has been planning to make the system support the "expected bank withdrawal" volumes. This may be the case; however, it certainly was not the reason that Ameren witness Normand stated he used 20% of usage for determining the underground storage cost allocation to transportation customers. (Ameren Ex. 16.0G, p. 10) In his surrebuttal testimony, when clarifying the reason for using Daily Confirmed Nomination ("DCN") instead of usage, he says nothing about the reliability of "expected usage" versus "expected DCN." (Ameren Ex. 57.0, pp. 3-6)

Ameren has designed the system for a Critical Day ("CD"). Therefore, it is appropriate to compare the relationship between expected usage and DCN on a CD, rather than simply on an historic peak day. However, Ameren's brief continues to make the same flawed argument that plagued its witness, Mr. Normand, throughout his testimony. Ameren argues that bank withdrawals will be in excess of that allowed in the tariff. This is based on the assumption that customers will under-nominate on a CD. This is not creditable because of the adverse tariff conditions that exist on CDs. Usage in excess of nominations and allowed bank withdrawals are subject to significant penalties of over $6 per therm.[17]

Ameren states that it does not know what the DCN will be on those peak days, (Ameren IB, p. 223) but Ameren does not know usage either. It must estimate both. While it may be easier to estimate usage on those days, DCN on a CD must be close to usage. If Ameren has chosen to plan its system based on bank withdrawals that are not supported by the tariff, this should not influence cost allocation. Transportation customers should pay based on what they can expect to withdraw on a CD. It is not either usage alone or DCN alone that dictates the level of bank usage; rather, it is the *difference* in DCN and usage. On a CD, these numbers will closely track because of Ameren's tariff provisions approved by the Commission to prevent one thing: the excess use of system gas that results from under-nomination.

Ameren states that "the transportation customers' DCN is discretionary and not predictable. A transportation customer can nominate as little as zero therms for a peak day, as much as 100% of MDCQ for daily-balanced customers, or 200% of MDCQ for monthly balanced customers." (*Id.*, pp. 222-223)

Just because customer's nominations are "discretionary" as Staff witness Sackett testified (Tr., p. 879, December 17, 2009) does not make them arbitrary as Ameren

[17] Ill. C.C. No. 20, 2nd Revised Sheet No. 25.007; Ill. C.C. No. 37, 2nd Revised Sheet No. 25.007; Ill. C.C. No. 19, 2nd Revised Sheet No. 25.007.

infers. Ameren has not established that its transportation customers individually do vary their nominations between 0 and 200% despite the allegation to that effect. Certainly this will not be the case when transportation customers are taken in aggregate. And the aggregate is what is at stake here. The maximum aggregate that Ameren alleges individual transportation customers can nominate is not the issue here because if transportation customers nominate and deliver up to Maximum Daily Contract Quantity ("MDCQ") or even 2 times MDCQ on a peak day, they would be *injecting* gas, not withdrawing it. Such nominations would only cause the transportation customers' aggregate bank usage to go *down*.

The minimum aggregate expected nomination would be a legitimate concern. However, on a CD, transportation customers have certain "rights" to nominate as stated by Ameren; they have certain obligations as well. Realistically, transportation customers would not nominate that little gas. The limiting factor on the potential under-nomination raised by Ameren in its brief are the CD Penalties.

All transportation customers, regardless of whether they are daily or monthly–balanced customers[18], face the $6-per-therm Unauthorized Gas Use Charge[19] which could be 10 times the price of gas on that day or more.[20] In addition, transportation customers would also face stringent Operational Flow Order ("OFO") Balancing provisions that charge transportation customers up to 2 times the spot price for the use

[18] A transportation customer that is monthly balanced is not required to have an interval meter. (Ill. C.C. No. 20, 1st Revised Sheet No. 4.019-2nd Revised Sheet No. 4.020; Ill. C.C. No. 37, 1st Revised Sheet No. 4.020; Ill. C.C. No. 19, 1st Revised Sheet No. 4.019-2nd Revised Sheet No. 4.020.) However, if a customer has in interval meter, it will get hit with CD penalties, just like a daily–balanced customer. (*Id*., 1st Revised Sheet No. 25.009) For those monthly-balanced customers without interval meters, they still may pay CD penalties if their monthly average usage is greater than their DCN on the CD. (*Id*.) This would keep customers from under-nomination on potential CDs.

[19] (*Id*., 2nd Revised Sheet No. 25.007)

[20] Assuming a Daily Chicago Citygate price of $.60 per therm.

of system gas.[21] Furthermore, transportation customers stand responsible for potential pipeline imbalances that they may cause.[22] All of these things combine to constrain transportation customers' nominations to a reasonable level. Ameren's assertion of wildly vacillating nominations between 0 and 200% of MDCQ is simply not founded upon the tariff. Ameren focuses on its specific right to serve the bank withdrawals of transportation customers; however, it ignores the other side of the tariff that is designed to protect the system on a CD.

According to Ameren, some customers may not be able to withdraw gas on the CD because they may lack sufficient capacity in those banks. (Ameren IB, p. 223) These customers will have to nominate below their usage to reduce the risk of Unauthorized Gas Use Charges, which would *reduce* the aggregate bank withdrawal below the 20% amount. Another reason listed by Ameren is that customers may choose to not use banks for commercial reasons. (*Id*.) Once again, this would mean that they would have to nominate *more* than they would otherwise and would also *reduce* the aggregate bank withdrawal. These examples of discretionary behavior actually point to a *lower* expected bank withdrawal. Ameren cannot point to a singe reason why transportation customers would *reduce* nominations on a critical day. And Ameren completely ignores the CD penalties which may be 10 times the market price or more.

Therefore, Staff continues to recommend that these customers be allocated the share of storage costs based on tariff rights that provide withdrawals of 20% of DCN rather the 20% of their peak day usage, which changes the storage allocator in Ameren

[21] *Id*.
[22] *Id*., 2nd Revised Sheet No. 25.008-1st Revised Sheet No. 25.009

Ex. 27.3 from 18.00% for AmerenCIPS to 14.02%, from 5.53% for AmerenCILCO to 3.96% and from 5.21% for AmerenIP to 3.80%. (Staff IB, pp. 160-161)

c. Other

VII. RATE DESIGN/TARIFF TERMS AND CONDITIONS

A. Overview

B. Resolved Issues

1. Gas and Electric

a. Combining Customer and Meter Charges

b. Customer Charge Label

c. Uncollectibles Factors – Riders EUA and GUA

2. Gas

a. Rate Limiter or Capping Mechanism

b. Overall Rate Design (Scale to Final Revenue Targets)

c. Interval Meter Data Access Fees

d. Calculation of "Highest Average Daily Use"

e. Transportation Tariff (Rider T)

(1) NAESB Intraday Nomination Cycles

(2) Notice for OFOs and Critical Days

3. Electric

a. Rider PER

b. Rider RDC

c. Rider BGS

d. Rider QF

e. Rider HMAC

f. Miscellaneous Tariff Language Changes

In his direct testimony, Staff witness Rukosuev addressed the proposed $170 meter reading fee for certain non-residential customers that fail to provide meter access or a telephone connection. (Staff Ex. 8.0, p. 4-7) Mr. Rukosuev conditionally agreed upon the proposed fee pending Ameren's amended language to explicitly restrict application of its proposed $170 charge to non-residential customers unambiguously. (*Id.*, p. 7) In its Initial Brief, Ameren inserted the appropriate tariff language addressing all of Mr. Rukosuev's concerns. (Ameren IB, Appendix H) Mr. Rukosuev reviewed the amended language in Appendix H and recommends approval of the proposed language changes since they are necessary to limit the proposed fee explicitly to non-residential customers.

g. Supply Cost Adjustments for Rider PER

(1) Supply Procurement Adjustment – Rider PER

(2) Uncollectibles Factor

h. DS-4 Reactive Demand Charge

C. Contested Issues

1. Gas

a. Availability Tariff Provisions

b. Large Customer Rate for Non-CILCO GDS-4

c. Seasonal Prices for all GDS Rates

d. Transportation Tariff (Rider T)

(1) Unbundling Banking Rights

Staff continues to recommend that the Commission order that the unbundled Rider T bank be based on on-system storage assets (like Nicor Gas) or total system assets (like Peoples Gas) and not just on off-system assets, and that the size of the individual customer's allocation be constrained so that total transportation bank capacity be no greater than the level determined in Section VII.C.1.d.(2). (Staff IB, p. 181)

(2) Size of Rider T Bank

Ameren asserts that the workshops should be open-ended without a clear requirement for any outcome. Furthermore, Ameren has indicated that it does not support an equitable allocation of these assets. If Ameren does not approach the workshops with clear guidance, it is unlikely that the process will produce results that enable the Company to include a consensus proposal in the next rate case. If that is the case, then these same issues will be argued again and the process will have been a waste of time.

Staff witness Sackett has provided sufficient evidence that the current allocation is inequitable. (Staff Ex. 14.0, pp. 22-24) The Commission should mandate an equitable process. Staff does not believe, and has not asked, for the Commission to order the usage of a particular method. Rather, Staff has asked that the Commission require that Ameren enter the workshops with a clear direction to equitably allocate its resources.

Ameren wants to create a subscribable bank without capacity allocation. However, the correct sequence to address these issues is to first decide the assets to be allocated. Then, one must decide how to allocate that capacity to determine the equitable capacity to allocate between sales and transportation customers. The final step in this process is to allow individual transportation customers to subscribe to their portion of that capacity.

The record in this case is sufficient for the Commission to determine that Ameren should follow the example of other gas utilities and to allocate its storage capacity equitably amongst all its customers.

Ameren objects that that the ten days of MDQ is equitable because it is more than it was before the last case. (Ameren IB, p. 267) Again, this is not a sufficient reason to conclude that we have arrived at an equitable allocation.

Ameren objects to Staff's proposal for the Commission to order an equitable capacity allocation as part of the workshop process:

> The Commission should, however, refrain from mandating specific tariff or rate structures or otherwise inhibit the workshop process. The workshop process will be best served by letting the participants determine the nature and scope of the discussions. An unfettered workshop process, for example, will permit the participants to identify the unbundling structures that best serve the AIUs and the customers. If they wish, any interested party can present alternative positions in the next rate cases. (*Id.*, pp. 261-262)

Staff does not see the Commission providing direction to a workshop to provide an equitable allocation of storage as inhibiting or fettering the workshop, but rather as reasonable guidance towards a set of desired outcomes. Ameren has already demonstrated a complete disregard for transportation customers' right to a share of Ameren storage assets when it proposed to eliminate access to storage by transportation customers in the previous rate case. (Order, Docket Nos. 07-0585 - 07-0590 (Cons.), September 24, 2008, p. 297) Staff believes, absent Commission direction, that the workshop process will be unlikely to provide a satisfactory consensus.

Ameren's brief reflects a fundamental misunderstanding of Staff's proposal to allocate capacity allow customers to select a level of bank along with the methodology used by other utilities. The brief states that it "would be inconsistent to allocate a fixed amount of capacity to these customers and permit them to choose the amount of capacity they desire." (Ameren IB, p. 263) However, Staff has proposed that the capacity allocation between transportation and sales customers should occur first and that the ensuing allocation of that capacity amongst transportation customers should be based on each customer's election. This is the process that is used by Nicor Gas. Ameren's inability to see that election and allocation are not mutually exclusive leads them to support the unbundling and subscribability and to overlook the capacity allocation upon which election must be based. As Staff pointed out in its brief, the practical result of Ameren's proposal is that it could result in transportation customers receiving a *greater*-than-equitable allocation. (Staff IB, p. 199)

Staff's illustrative use of the Commission approved methods to show what the capacity allocation would be, showed that the upper boundary of the total capacity must be set. There has never been any intent or proposal to force the transportation customers to take the new increased storage capacity.

Ameren advances in its brief a red herring regarding so-called "deficiencies" in these capacity allocation methods. It repeats the mantra that "there is no relationship between the seasonal storage working capacity and the peak day deliverability of the system." (Ameren IB, p. 266) However, Ameren continues to be unaware of the concept. Ameren infers a suggestion here on the part of whoever uses the Nicor Gas and Peoples Gas methods. If you attempt to give operational significance to the result of the capacity allocation calculation, you get some unattainable suggestions. However, as Mr. Dothage made clear in the hearing, the Commission, Staff and Nicor Gas all use these methods to allocate seasonal capacity, not to represent peak day deliverability. (Tr., p. 837, December 17, 2009)

Ameren claims that Staff fails "to appreciate the difference between a storage field's peak day deliverability and its total storage capacity. A storage field cannot release 100% of the gas in storage on the peak day." (Ameren IB, p. 266) Staff does appreciate the fact noted by Ameren. However, Staff does not attempt to force an operational answer to a non-operational question; it does not attempt to infer peak day significance from a seasonal capacity allocation. The facts cited by Ameren are, of course, also true for both Nicor Gas and Peoples Gas and should not be lost on the Commission, as implied by Ameren's statements of the obvious. Because the Commission has approved these methods in both Nicor Gas and Peoples Gas, Ameren implies by extension that the Commission also fails to appreciate this obvious fact.

Ameren's confusion on this issue is further illustrated by the calculations provided in Ameren's brief on pages 265 and 266. The equations should be corrected to replace the term "Days of Deliverability" with "Days of Bank." The term "Days of Bank" refers not to how much peak day withdrawal rights but rather maximum storage capacity in the LDC's system. Ameren witness Mr. Dothage acknowledged this in the hearing. "The mathematical result of the division of the seasonal storage capacity by the peak sendout of the system boils down to a number of days, X number of days, and that X number of days is the number of days that transportation customers on the Nicor system have bank service." (Tr., pp. 836-837, December 17, 2009) Thus, the Nicor method does not yield days of deliverability but rather days of bank.

The red herring on deficiencies further illustrates why it is unreasonable to give Ameren an open hand in the workshop process. Ameren's witness Dothage is the only one to see this "deficiency" because he is the only person connected with this issue that sees this lack of an operational significance as a deficiency. (Tr., p. 837, December 17, 2009) The fact is that Ameren has allocated annual storage costs using a relative peak day allocator and it is appropriate to allocate the seasonal capacity based on the way that annual storage costs are allocated. (Staff Ex. 27.0, p. 39)

Therefore, Staff continues to recommend the Commission order Ameren to work with Staff and Intervenors to develop an equitable allocation process for storage assets, to allow customers to select the level of banking that best suits their needs, and to develop an equitable allocation of the costs of providing those services. Ameren should be required to propose these changes in its next rate case. (Staff IB, p. 200)

e. Other

2. Electric

a. Rate Moderation/Mitigation Approaches

The efforts by both the Companies and the IIEC to defend their proposed rate moderation plans fall short. These arguments provide further reason why the Commission should adopt Staff's proposed revenue allocation in this proceeding.

The Companies begin by noting that all three parties presenting revenue allocation proposals in this case, the AIUs, Staff and IIEC, present proposals that are only partly cost-based. (Ameren IB, p. 269) The AIUs go on to criticize the Staff proposal to limit revenue increases to 150% of the system average, claiming it "puts a disproportionate burden on classes DS-3 and DS-4, and, consequently, widens the gap between DS-3 and DS-4 on a dollar per kW demand charge basis." (*Id.*, p. 270) Because of an alleged "disproportionate burden created for DS-3 and DS-4," the Companies contend that Staff's approach should be rejected. (*Id.*)

The Companies claim that their proposed revenue allocation "provides a better balance between movement toward cost-based rates and mitigating bill impact." (*Id.*) As evidence, they note that their proposal limits the increases for DS-1 through DS-4 (but not DS-5) to 125% of the system average increase. They also suggest that their proposed revenue allocation offers the further advantage of excluding distribution taxes from the rate mitigation process. The Companies state, "[b]ecause the distribution tax is assessed to the utility on a kWh or energy basis, it should be assessed to customers in the same manner, without effectuating cross-subsidies that would otherwise invariably be created by rate mitigation strategies." (*Id.*, p. 271)

This argument suffers from a fundamental problem. That is the AIUs' unfounded belief that distribution taxes should receive different treatment from all other costs in the rate mitigation process due to the fact that they are "assessed to the utility on a kWh or energy basis." The Companies' argument assumes that ratepayers care about bill impacts due to some costs, but not distribution taxes. However, there is no record evidence to support that belief. The more reasonable assumption is that ratepayers care about increases in all components of their electric bills including distribution taxes. (Staff Ex. 7.0, pp. 16-17)

Despite the weakness of this argument, the Companies criticize Staff for including distribution taxes in its proposed revenue allocation constraint. The AIUs contend that this would create problems for customer classes. They go on to claim that

Staff "acknowledged that using AmerenCILCO as an example, DS-4, DS-3, and DS-2 customers would be receiving a subsidy on a class total revenues basis, inclusive of a portion of the distribution tax associated revenue requirement." (Ameren IB, p. 271)

This argument only underscores the contradiction in the position of the AIUs. On the one hand, they contend that Staff's 150% constraint "puts a disproportionate burden on classes DS-3 and DS-4," but then the AIUs complain that Staff's approach to distribution taxes would subsidize DS-3 and DS-4 as well as the DS-2 class. So they argue at the same time that Staff's approach both burdens and subsidizes the DS-3 and DS-4 classes. This confused argument can be readily dismissed by the Commission.

Thus, discussion in the Ameren Initial Brief serves to weaken, rather than strengthen, the Companies' position. Their proposed exceptions for both DS-5 customers and for distribution taxes produce arbitrary and inequitable results for ratepayers as a whole. This approach is clearly inappropriate and should be rejected by the Commission.

The IIEC joins Staff in attacking the Companies' proposed revenue allocation and argues that "Ameren has done an exceedingly poor job of mitigating the delivery service cost increases for the DS-4 class in general and the higher voltage DS-4 sub-classes and customers in particular." (IIEC IB, p. 95) The IIEC clearly finds the Staff approach preferable, stating "IIEC and the ICC Staff have provided more balanced and comprehensive rate moderation proposals in the context of this case." (*Id.*)

The IIEC also presents an alternative set of revenue allocations for the Commission to consider. Its original proposal sought to limit increases for all subclasses to 25% above the system average increase. However, due to concerns it raised about the Companies' proposed cost of service study, IIEC came to advocate an across-the-board increase for all rate classes of each Company. (*Id.*, p. 101)

The IIEC proposals do not appear to satisfactorily address the Commission's concerns about returning the focus of Ameren ratemaking to cost of service. It should be remembered that the Commission stated in Ameren's previous rate case that it "finds value in Staff's recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases." (Final Order, Docket Nos. 07-0585 et al. (Cons.), September 24, 2008, p. 281) Neither the IIEC's proposed across-the-board allocation nor its limited constraint of 25% over the system average increase at the subclass level appears to be consistent with the Commission's statement.

There is further reason to consider a more cost-based approach to revenue allocation in this docket. Staff has noted that Supply costs for bundled customers fell significantly in June 2009, by approximately 13% on average for the residential customers of the Companies. (Staff Ex. 7.0, p. 28) To the extent that this decrease reflects falling prices in the wholesale power market, customers would be able to balance reductions in the power component of electricity service against increases in delivery rates. Thus, with power costs declining, now would be a good time to adopt a more cost-based revenue allocation than proposed by the IIEC.

b. Overall Rate Design

The key overall rate design issue between Staff and the Companies concerns the conformance of rates to the final revenue requirement. The AIUs present a flawed argument in their Initial Brief for an unnecessarily complex approach which does not benefit the ratemaking process. The Companies begin their discussion by complaining that "Staff dismisses the AIUs' proposed rate adjustment methodology, for no other reason than because Staff deems its methodology to be the simplest." (Ameren IB, p. 274) The AIUs contend that their proposal "provides a better balance between movement toward cost-based rates and mitigating bill impacts" and contend that the Staff alternative passes on the opportunity to further address subsidy elimination, rate continuity, bill impacts and concerns raised by other parties. (*Id.*)

The deficiency in the AIUs' argument is that compliance rates are not a good place for adjusting rates to meet specific rate design objectives. Any changes to rates at that juncture have important implications for all Ameren ratepayers. To the extent that one rate element is adjusted and another is not, certain ratepayers will benefit while others will be disadvantaged. The problem for those who lose out is that they have no recourse at this stage of the process. They will have to wait until the next rate case to seek redress. (Staff IB, pp. 222-223)

In contrast, the Staff equal percentage adjustment approach does not make further rate changes in the compliance process. All parties will understand that approved rate elements will all be adjusted on an equal percentage basis to achieve the final revenue requirement. This is clearly the more transparent and straightforward approach. (Staff Ex. 21.0, pp. 20-21)

c. Recovery of Electric Distribution Tax/Public Utilities Revenue Act Tax

d. Distribution Delivery Charges: DS-3 and DS-4

The Companies' discussion of DS-3 and DS-4 rate design underscores the deficiencies that make their methodology unsuitable for ratemaking in this case. They begin their discussion with class revenue allocations, criticizing Staff's recommendation because it raises the revenue responsibility for DS-3 relative to DS-4. The Companies believes this creates problems for the largest DS-3 customers because it would encourage them to increase their demand and switch to lower DS-4 rates. (Ameren IB, pp. 277-278)

The Companies go on to reject a Staff argument that said the increases in DS-3 rates Staff proposes "will be mitigated to the extent that the Commission adjusts the revenue requirement downward." (*Id.*, p. 278) The Companies find this argument lacking because "relative differences in the revenue requirements and price disparity remains." (*Id.*) The AIUs contend that their proposed rates for the two classes are closer together and thereby fit better with the Companies' more equal class revenue allocations between the two classes. (*Id.*)

The Companies' arguments should be rejected. They are designed to support a fundamentally flawed revenue allocation to the DS-3 and DS-4 classes. Their focus on the relationship between DS-3 and DS-4 rate levels is entirely misplaced. As Staff has noted, the appropriate traditional approach to ratemaking is to first allocate costs to individual rate classes and then recover the attendant costs through rates designed for each individual class. It is illogical to allocate costs separately to the DS-3 and DS-4 classes and then implement a collective rate design that tries to paper over the cost differences between the two. This is not cost-based ratemaking. Rather, it applies faulty logic to support a specific end-result.

And, in fact, the Company acknowledges this to be true when it states that “the AIU’s approach addresses the concerns of many of the parties. For example, the AIUs’ rate adjustment approach reduces DS-3 Distribution Delivery Charges, which closes the gap between DS-3 and DS-4 – a concern of Kroger.” (*Id.*) The Companies further note that their proposal “reduces the amount of rate limiter credits – a goal of GFAI.” (*Id.*)

It should be remembered that rate design is a zero sum game. For every winner in the process, there is a loser. Thus, it is essential that rates be designed in a fair and equitable manner to all. The Commission has concluded that fairness means basing rates on costs. The Staff approach would adhere to this standard for DS-3 and DS-4 customers. The Companies’ approach would not. (Staff Ex. 7.0, pp. 36-37)

e. Fixture and Distribution Delivery Charges: DS-5

The Companies’ discussion of DS-5 rates obscures the significant problems with their proposals for the class. They focus on the goal of uniformity for the class across all three companies and criticize Staff for failing to make this a priority. (Ameren IB, pp. 279-280) For one, they criticize Staff for ignoring ”the arguments of the Cities from Docket No. 07-0585 (Cons.) that Fixture Charges be brought closer together.” The Companies further argue that the Staff proposal “does not adequately address the Commission’s inquiries about moving Fixture Charges closer together that were expressed in the prior rate order.” They also complain about Staff not “using the incremental cost study as a guide…because of outside vendors competing against the AIUs standard fixture offerings.” (Ameren IB, pp. 279-280)

These arguments are problematic in a number of respects. First, it should be remembered that Staff's proposed rates for this class are based on the Companies' proposed rates prorated down to the Staff-proposed revenue requirements. So, the Staff rates are as consistent as possible with the Companies' proposed rates within the constraints of Staff's proposed revenue allocations. (Staff Ex. 21.0, pp. 19-20)

In addition, revenue requirements are set separately at the three AIUs and DS-5 customers receive separate and independent cost allocations for the three utilities. Because the utilities have separate and unique cost structures, it is only a matter of chance that the different cost studies will allocate a similar level of costs and produce similar rate charges for DS-5 customers in the three Companies. And if they do not, as is the case in this proceeding, some adjustment process becomes necessary to equalize DS-5 rate levels for the three AIUs. That adjustment process can skew revenue allocations and rate levels not just for the DS-5 classes but for other classes as well. That has been the case for the three AIUs where under the guise of moving towards uniformity in lighting rates, the AIUs have allocated significantly higher revenues to the DS-5 classes than justified by the cost of service and rate mitigation rules applied to other rate classes. (*Id.*, p. 12)

With regard to the issue of incremental costs, the Companies once again apply separate rules to lighting customers. They are the only class for whom the Companies consider incremental costs in the revenue allocation process. This selective use of incremental costs to support a higher revenue allocation is clearly unfair to lighting customers. (*Id.*, p. 13)

The Companies describe their own ratemaking proposals for the DS-5 class as "methodical," stating "the goal is to make progress toward uniform rates, easing AmerenIP rates lower and AmerenCIPS rates higher." However, they go on to note that "[s]ince each of the AIUs are a single legal entity, any revenue excess or deficiency still needs to remain within the individual utility, and should be absorbed by other rate classes." (Ameren IB, p. 280)

The Companies' discussion unintentionally identifies the conundrum created by their proposed ratemaking strategy for DS-5. Somehow, they seek to create rate uniformity across three companies when costs are allocated to each separately based upon the unique costs for the respective utility. The only way to produce uniform lighting rates in this situation would be by deviating from costs not just for lighting customers but for other classes as well. The only reasonable way to achieve rate uniformity for the three lighting classes would entail designing their rates based on the cost of service for the AIUs as a whole. To achieve this goal based on Ameren's ad hoc approach would create uniformity at the expense of cost-based ratemaking. This would be a suboptimal result from the standpoint of both fairness and economic efficiency.

f. Tail Block Variable Charges: BGS-1

g. Combined Billing of Multiple Meters

h. Rate Limiter/Cost-Based Seasonal Rate

i. Other

VIII. CONCLUSION

For the reasons set forth in its Initial Brief and this Reply Brief, Staff respectfully requests that the Commission's Order in the instant proceeding reflect Staff's modifications to the Companies' proposed general increases in rates for gas and electric delivery services.

Respectfully submitted,

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