STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company d/b/a Ameren Illinois	:	11-0279
Proposed general increase in electric delivery service rates. (Tariffs filed February 18, 2011).	:	
Ameren Illinois Company d/b/a Ameren Illinois	:	11-0282
	:	(Consolidated)
Proposed general increase in natural gas rates. (Tariffs filed February 18, 2011).	:	

INITIAL BRIEF OF THE STAFF OF THE ILLINOIS COMMERCE COMMISSION

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NOW COME the Staff witnesses of the Illinois Commerce Commission ("Staff"), by and through their undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's Rules of Practice (83 Ill. Adm. Code 200.800), and respectfully submit their Initial Brief in the instant proceeding.

I. INTRODUCTION

A. Overview

On February 18, 2011, the Ameren Illinois Company d/b/a Ameren Illinois (collectively, "Ameren," "AIC," or "Company") filed with the Illinois Commerce Commission ("Commission") revised tariff sheets in which they proposed a general increase in electric and gas rates pursuant to Article IX of the Illinois Public Utilities Act ("Act" or "PUA"), 220 ILCS 5/9, to become effective April 4, 2011.

B. Procedural History

On March 23, 2011, the Commission suspended the filing to and including July 17, 2011, for a hearing on the proposed rate increase. On April 8, 2011, the electric and gas cases were consolidated. On July 7, 2011, the Commission re-suspended the tariffs to and including January 17, 2012.

The following Staff witnesses have submitted testimony in this case: Scott Struck (Staff Exs. 1.0 and 19.0), Dianna Hathhorn (Staff Exs. 2.0R and 20.0), Bonita A. Pearce (Staff Exs. 3.0 and 21.0), Scott Tolsdorf (Staff Exs. 4.0 and 22.0R2), Mary H. Everson (Staff Ex. 5.0), Burma C. Jones (Staff Exs. 6.0 and 23.0), Rochelle Phipps (Staff Exs. 7.0 and 24.0), Janis Freetly (Staff Exs. 8.0 and 25.0R), Mark Maple (Staff Exs. 9.0 and 26.0), Greg Rockrohr (Staff Ex. 10.0), Mona Elsaid (Staff Exs. 11.0R and 27.0), Yassir Rashid (Staff Exs. 12.0 and 28.0), David Sackett (Staff Exs. 13.0 and 29.0), Peter Lazare (Staff Exs. 14.0 and 30.0), Philip Rukosuev (Staff Exs. 15.0 and 31.0), Torsten Clausen (Staff Exs. 16.0 and 32.0), Eric Lounsberry (Staff Ex. 17.0), David Brightwell (Staff Exs. 18.0 and 33.0R), and David Reardon (Staff Exs. 34.0).

The following Petitions to Intervene were also granted in this matter: Citizens Utility Board ("CUB"); People of the State of Illinois ("AG"); the Kroger Company; Illinois Industrial Energy Consumers ("IIEC"); Grain & Feed Association of Illinois ("GFAI"); AARP; the Commercial Group; Dominion Retail, Incorporated and Interstate Gas Supply of Illinois, Incorporated, collectively the Retail Gas Suppliers ("RGS"); Illinois Competitive Energy Association; and System Council U-05 of the International Brotherhood of Electrical Workers, AFL-CIO ("IBEW").

An evidentiary hearing was held in this matter on September 12-16, 2011. The record was marked Heard and Taken. Appendices A, B, and C attached hereto include the Revenue Requirement Schedules proposed by Staff for the electric rate zones, Rate Zone 1, Rate Zone 2, and Rate Zone 3, respectively. Appendices D, E, and F include the Revenue Requirement Schedules proposed by Staff for the gas rate zones, Rate Zone 1, Rate Zone 2, and Rate Zone 3, respectively. Appendices G and H include the Revenue Requirement Schedules proposed by Staff for the total Electric and Gas, respectively.

C. Nature of AIUs' Operations

D. Test Year

AIC proposed to use a future test year for the twelve months ending December 31, 2012 in this matter. No party objected to the use of this test year.

E. Legal Standard

All rates set by the Commission must be "just and reasonable" and any "unjust or unreasonable" rate is unlawful. In this regard, Section 5/9-101 of the PUA provides, in relevant part, that:

> All rates or other charges made, demanded or received by any product or commodity furnished or to be furnished or for any service rendered or to be rendered shall be just and reasonable. Every unjust or unreasonable charge made, demanded or received for such product or commodity or service is hereby prohibited and declared unlawful. All rules and regulations made by a public utility affecting or pertaining to its charges to the public shall be just and reasonable. (220 ILCS 5/9-101)

II. RATE BASE

A. Overview

B. Resolved Issues

1. Liberty Plant Additions

Staff witness Hathhorn proposed adjustments to reduce AIC's electric rate base and operating expenses for forecast plant additions that are not expected to be placed in service until after December 31, 2012, the end of the future test year. (Staff Ex. 2.0R, p. 10 and Sch. 2.04) However, Staff withdrew the adjustments in rebuttal testimony after Ameren's rebuttal testimony (Ameren Ex. 26, p. 3) clarified information Ameren had provided in discovery. (Staff Ex. 20.0, p. 4)

2. Alton Propane Facility Retirement

Ameren noted it retired its Alton Propane Plant at the end of 2010. (Staff Ex. 17.0, p. 6) Staff indicated that that its review found no reason to dispute Ameren's decision to retire this facility. (*Id.*) However, Staff initially proposed adjustments to remove the various costs associated with the facility from Ameren's rates. (Staff Ex. 4.0, Schedule 4.03, Staff Ex. 2.0R, Schedule 2.10) In response to Staff's proposal, Ameren demonstrated that it had already removed all of the facility's costs from its requested rates. (Ameren Ex. 22.0, p. 31, Staff Ex. 20.0, p. 3) Therefore, no adjustments are necessary on this issue.

3. Hillsboro – Used and Useful

Appendix F incorporates the Hillsboro Storage Field used and useful allowance based on the non-common equity components of Staff's rate of return. This adjustment, which AIC proposed in its direct testimony, was inadvertently omitted by Staff in its direct testimony. Staff incorporated this uncontested adjustment in its rebuttal testimony. (Staff Ex. 19.0, p. 4; Ameren Ex. 22.0, pp. 30-31; Ameren Ex. 40.0, p. 6)

4. Property Held for Future Use

Staff witness Hathhorn proposed an adjustment to reduce AIC's electric rate base for Rate Zone I for allowance for funds used during construction ("AFUDC") amounts inadvertently charged to property held for future use. (Staff Ex. 2.0R, p. 13 and Sch. 2.06) The Company stated that under AIC's AFUDC policy, AFUDC shall not be charged for the purchase of land that does not provide for construction of facilities within a reasonable time period after purchase. (Company Response to Staff DR DLH-15.06) The Company acknowledged that it was incorrect to record this AFUDC charge. (*Id.*) The Company accepted Staff's adjustments and included them in its rebuttal revenue requirements. (Ameren Ex. 22.0, p. 7)

5. Federal Income Tax ADIT Correction

Staff witness Hathhorn proposed adjustments to decrease AIC's electric and gas federal ADIT amounts, thereby increasing rate base, to correct the error of unreasonable amounts identified in Ameren Ex. 16.2, Schedule 1. (Staff Ex. 2.0R, p. 9 and Sch. 2.03) The Company explained that its ADIT schedules contain an error related to an incorrect sign on the deferred tax asset related to federal net operating loss, and correction of this error results in a net change to property related to ADIT. (Ameren Ex. 17.0, p. 2) The Company accepted Staff's adjustments and included them in its rebuttal revenue requirements. (Ameren Ex. 22.0, p. 7)

6. State Income Tax ADIT – Bonus Depreciation

Staff witness Hathhorn proposed adjustments to increase AIC's electric and gas state accumulated deferred income tax ("ADIT") amounts, thereby decreasing rate base, because the Company's proposed amounts did not reflect the effect of federal bonus depreciation on the state ADIT liability and were therefore unreasonable. (Staff Ex. 2.0R, p. 8 and Sch. 2.02) The Company's position was based on Illinois' past practice of decoupling from federal tax provisions for bonus depreciation. (Ameren Ex. 10.0, p. 6) However, the Company stated in discovery that the State of Illinois has not passed legislation to follow its past treatment of decoupling from the federal tax provisions of bonus depreciation. (Staff Ex. 2.0R, p. 8 and Sch. 2.02) The Company accepted Staff's adjustments and included them in its rebuttal revenue requirements. (Ameren Ex. 22.0, p. 7) The Company further stated that the AG/CUB proposed adjustment for ADIT-Bonus Depreciation is very similar to Staff's adjustment that it accepted.

7. ADIT – Manufactured Gas

8. Materials and Supplies

Staff witness Tolsdorf proposed an adjustment to materials and supplies based upon the Direct Testimony presented by Staff witness Eric Lounsberry (Staff Ex. 17.0) and Staff witness Mark Maple (Staff Ex. 9.0). Mr. Lounsberry's adjustment concerned the retired Alton propane plant discussed earlier in this brief. (See Section II. B. 2 above) Mr. Maple's adjustment concerned the value of gas stored underground discussed later in this brief. (See Section II. B. 11 below) Both Mr. Lounsberry and Mr.

Maple's adjustments to materials and supplies were withdrawn in Mr. Tolsdorf's Rebuttal Testimony. (Staff Ex. 22.0R2, p. 2)

9. Customer Deposits

Staff witness Tolsdorf proposed adjustments to rate base reflecting an average annual growth trend in customer deposits continuing through the test year. (Staff Ex. 4.0, p. 3) Mr. Tolsdorf withdrew this adjustment in rebuttal testimony upon further information provided by the Company. (Staff Ex. 22.0R2, p. 2)

10. Budget Payment Plans

Staff witness Tolsdorf proposed adjustments to rate base for the average over-collection balance of budget payment plans forecasted by the Company for the test year. (Staff Ex. 4.0, p. 4) Staff's adjustment was accepted by AIC in rebuttal testimony. (Ameren Ex. 22.0, p. 7)

11. Gas in Storage

Staff witness Maple expressed a concern that Ameren relied upon out-dated gas pricing information to forecast its 2012 test year costs associated with its 13-month valuation of its working capital allowance for gas in storage and recommended that the Company use the more recent May 2011 gas prices. (Staff Ex. 9.0, pp. 5-9) Mr. Maple also recommended a minor adjustment to the volume of gas forecasted for AmerenCILCO's working capital in the test year. (*Id.*, pp. 8-9) Ameren agreed to accept Staff's adjustment using the more recent gas prices, but did not agree to the volume adjustment due to a change in the Company's strategy. (Ameren Ex. 35.0, pp. 9-11) Ameren witness Seckler put forth updated numbers that removed Staff's volume adjustment for the working capital allowance in Ameren Ex. 35.1. Staff does not dispute the Company's updated 13-month valuation of working capital allowance for gas in storage, as shown in Ameren Ex. 35.1. (Staff Ex. 26.0, p. 3)

12. Merger Costs

In its filing, Ameren included in the test year approximately $4 million of O&M savings and $2.3 million of O&M costs related to the merger integration/process optimization study. In addition, the Company included in test year rate base approximately $1.4 million of capital cost savings and $3.3 million of capital costs related to the merger integration/process optimization study. (ICC Staff Exhibit 3.0, p. 15) Staff initially objected to these costs on grounds that AIC had failed to demonstrate that the cost savings associated with the merger exceeded associated costs and that internal labor costs were improperly included in the total merger costs. (*Id*., pp. 15, 17)

After further clarification by the Company, Staff has withdrawn its objection to the merger costs, and this issue is no longer considered contested between Staff and the Company. (Staff Ex. 3.0, pp. 14 – 18; Schedule 3.06; Staff Ex. 21.0, pp. 16 – 18; Schedule 21.03)

AG/CUB witness Mr. Effron proposed to eliminate all amortization of merger costs until such time as the costs are known and it can be established that expected savings from the merger are actually being realized. (AG/CUB Ex. 4.0, p. 6) Given that the Company has used a future test year, Staff accepts that not all of the merger costs will be based on amounts that are known at this time. Initially, Staff shared Mr. Effron's concerns about the merger cost/savings calculations provided by the Company and about the merger savings not being reflected in the test year, as well as internal labor costs that were included in the initial calculations provided by the Company. Subsequently, however, the Company removed the internal labor costs and provided additional clarification regarding merger savings to address Staff's concerns. (Staff Ex. 21.0, pp. 17 – 18)

13. Wages and Salaries and Employee Benefits

Staff proposed a six percent reduction of forecasted 2012 test year wages and salaries and employee benefits based on information contained in the Merger Integration and Process Optimization ("MIPO") Study attached to the direct testimony of Company witness Mr. James Mazurek. (Staff Ex. 3.0, pp. 11 – 13; Schedules 3.03 and 3.04)

Based on information provided by various Company witnesses in rebuttal testimony, Staff withdrew this adjustment in rebuttal testimony. (Staff Ex. 21.0, p. 16)

14. Previously Disallowed Incentive Compensation

Staff proposed to reduce rate base for capitalized incentive compensation amounts that had been previously disallowed by the Commission, as detailed on Staff Exhibit 3.0, Schedule 3.05. Company witness Stafford accepted Staff's adjustment in rebuttal testimony. (Ameren Ex. 22.0, p. 7)

C. Contested Issues

1. Capital Additions Adjustment

Staff witness Yassir Rashid recommends that the Commission disallow $7,246,868 from Ameren's proposed rate base, which is the cost of sixteen projects that Ameren will not implement by the end of the test year, because these projects will not be used and useful by the end of test year as required by Section 9-212 of the PUA (220 ILCS 5/9-212). Section 9-212 provides in pertinent part:

> . . . A generation or production facility is used and useful only if, and only to the extent that, it is necessary to meet customer demand or economically beneficial in meeting such demand. No generation or production facility shall be found used and useful until and unless it is capable of generation or production at significant operating levels on a consistent and sustainable basis. . .

Mr. Rashid reviewed information on fifty projects that Ameren indicated it plans to implement in 2011 and 2012. These include forty projects that Mr. Rashid reviewed prior to filing his direct testimony; i.e. ten out of twelve projects that Ameren included in its Schedule F-4, which is part of Ameren's Part 285 filing in this docket; and the thirty most expensive projects following those included in the Schedule F-4.[1] In addition, Mr. Rashid reviewed ten out of thirteen projects that Ameren did not initially plan to implement before the end of test year, but identified in rebuttal testimony as additional projects it will complete by the end of the 2012 test year[2]. In his direct testimony, Mr. Rashid concluded that Ameren would not complete two of the forty projects he reviewed before the end of the test year[3]. In addition, Mr. Rashid asked that Ameren state whether it included other projects in its proposed rate base with completion dates after the end of test year.

[1] See Staff Ex. 12.0, page 6.
[2] See Staff Ex. 28.0, page 5.
[3] See Staff Ex. 12.0, pages 8 -10.

In response to Staff's proposed adjustment, Ameren introduced Ameren Exhibit 26.1, which included a list of sixteen projects that Ameren initially included in its proposed rate base, but later decided to defer or cancel. The combined cost of these projects is $7,246,868. Ameren Exhibit 26.1 also includes a list of thirteen projects that Ameren labeled as "projects not included in rate base added in 2011-2012."[4] The combined cost for these projects is $8,785,052. Ameren indicated that it did not update its schedules to reflect these changes because "it did not identify any changes to the forecast "significantly and materially" affecting the revenue requirement."[5] Although Ameren did not propose adjustments to include these thirteen projects in its rate base[6], Ameren argues that the Commission should allow it to use the money it originally allotted to implement the sixteen delayed and cancelled projects for the implementation of the thirteen new projects that it identified in response to Mr. Rashid's discovery of those delayed and cancelled projects.[7]

The Commission should not allow Ameren to make these substitutions. It is Ameren's responsibility to provide the Commission with accurate forecast of test year capital projects expense that may be reviewed to determine whether they are prudent and used and useful.[8] Ameren's forecast for test year capital additions was not accurate. Therefore, the Commission should disallow $7,246,868 from inclusion in Ameren's proposed rate base.

[4] See Ameren Ex. 26.1, page 2.
[5] See Ameren Ex. 39.0, page 8.
[6] See *Id.,* page 7.
[7] See Ameren Ex. 44.0, page 4.
[8] Section 9-211 of the Act states, "[the] Commission, in any determination of rates or charges, shall include in a utility's rate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers."

2. ADIT – FIN 48

AG/CUB argues that ADIT that the Company reclassified to FIN 48 liabilities in the amount of $34.467 million (electric only) is related to uncertain tax positions and represent non-investor supplied funds that are available to the Company. (AG/CUB Ex. 1.0, p. 8) AG/CUB states that the effect of the Company's position reduces the ADIT deducted from plant in service in the determination of rate base. (*Id.*, p. 7)

FIN 48 is an interpretation clarifying the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, Accounting for Income Taxes. FIN 48 requires a two-step evaluation of tax positions. First, an enterprise determines whether it is more likely than not that a tax position will be sustained upon examination based on the technical merits of the position, including resolution of any related appeals or litigation processes. Second, a tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefits to recognize in the financial statements. (Financial Accounting Series, FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109, No. 281B -June 2006, Summary) (Staff Ex. 20.0, p. 10)

The Company's rebuttal witness Warren (Ameren Ex. 37.0), after explaining some basic principles about traditional ADIT versus ADIT arising from uncertain tax positions in accordance with FIN 48 (*Id.*, pp. 4-6), states that the ADIT related to Mr. Effron's FIN 48 adjustment is not a loan of funds to the Company in the traditional ADIT sense, which requires a rate base deduction, but rather represents the amount of tax that is more likely than not to be paid to taxing authorities in connection with uncertain tax positions and must be reflected by the Company on its balance sheet as a tax liability, with interest. The Company states that the FIN 48 amounts represent the incremental quantity of tax that the Company and its auditors have concluded it will most likely owe with respect to previously filed tax returns, and that the amounts will be payable with interest when they are assessed. (*Id*., p. 9) The Company argues that rate base should not be reduced for the FIN 48 amounts since the amounts are neither real nor sustainable as they are likely to be paid to taxing authorities with interest. (*Id.*, p. 10) Finally, the Company states that Mr. Effron's position assumes, in effect, that the Company will prevail on *every* uncertain tax position it has taken -- even on those with respect to which the experts have determined it is likely the Company will *not* prevail. (*Id*., lines 208-210; emphasis in original) (Staff Ex. 20.0, pp. 10-11)

In discovery, the Company stated that it reflected the total increase to electric ADIT of approximately $81.9 million in its Schedules B-9. (Staff Ex. 20.0, Attach. A) These increases to ADIT offset or reduce rate base reflected in the Company's Schedules B-1. The uncertain tax positions from FIN 48 offset these ADIT liabilities by approximately $34.5 million. Therefore, the Company's combined electric rate base still is approximately $47.4 million lower ($81.9 - $34.5) reflecting the net impact of the accounting method change and the FIN 48 amounts.

The Company has agreed to not seek recovery from its ratepayers if the Internal Revenue Service ("IRS") ultimately requires any interest or penalties on the FIN 48 amounts provided that the ICC, pending a final IRS determination, makes no adjustment for rate-making purposes to the Company's deferred taxes because of the FIN 48 amount. (Staff Ex. 20.0, Attach. B) Staff agrees that this is a reasonable approach and, therefore, recommends that the Commission not adopt the AG-CUB adjustment; i.e., the AG-CUB ADIT adjustment is not reflected in Staff's revenue requirement schedules attached to its initial brief.

3. Cash Working Capital

Only one issue remains contested between the Company and Staff with respect to the calculation of cash working capital (CWC). The Company proposes that ratepayers be responsible for the cost of Ameren's decision to pay Energy Assistance Charges a month early. Staff believes that ratepayers should not bear the cost of Ameren's unnecessary early payment.

At issue is the timing of the remittance to the appropriate taxing authority of the energy assistance charges collected by the Company. The Company remits these funds to the taxing authority in advance of statutory requirements. Staff witness Tolsdorf proposes that the calculation of the time that the Company has access to these funds should be based upon when the Company is required by law to remit the funds rather than when the Company chooses to remit them. (Staff Ex. 22.0R2, p. 15) The enabling legislation for the Energy Assistance Charge provides that:

> By the 20th of the month following the month in which the charges imposed by the Section were collected, each public utility, municipal utility, and electric cooperative shall remit to the Department of Revenue all moneys received as payment of the Energy Assistance Charge…." (305 ILCS 20/13(f))

The above statutory language clearly provides that the Energy Assistance Charge payment is due by the 20th of the month following the month of collection. The Company does not dispute this interpretation. In surrebuttal testimony, the Company's witness Mr. Heinz states in part:

> Mr. Tolsdorf contends that, under the enabling legislation, the Energy Assistance Charges are due by the 20th of the month following the month

> in which charges were collected. Thus, Mr. Tolsdorf calculates the Company has access to the funds for 35 days, instead of 4 days.
>
> Q. Does the Company disagree with Mr. Tolsdorf's interpretation of the enabling legislation?
> A. No. (Ameren Ex. 43.0, p. 3)

The Company and Staff are in agreement that the CWC requirement attributable to pass-through taxes, such as the Energy Assistance Charge, should be based on the amount of time the Company has access to the funds. The Company and Staff are also in agreement that the Company must remit the Energy Assistance Charge collected to the taxing authority no later than the 20th of the month following the month of collection. The Company has access to these funds until the 20th of the month following the month of collection. The decision to pay the Energy Assistance Charge early is purely that of the Company, and is unnecessary. Accordingly, the CWC calculation should be based on the Company's access to these funds and not the date the Company chooses to remit them.

4. Accrued OPEB Liability

The Commission should accept Staff's proposed adjustment to reduce rate base for the projected average Other Post-employment Benefits ("OPEB") liability for the test year ending December 31, 2012. The OPEB liability represents a cost-free source of capital that was provided by ratepayers. As such, the ratepayers should not have to pay a return on it. Staff identified numerous cases in which the Commission has concluded that OPEB liability should be treated as a reduction of rate base. Staff specifically noted the following rate cases: Peoples Gas/North Shore Gas Docket Nos. 07-0241/07-0242 (Cons.); Peoples Gas/North Shore Gas Docket Nos. 09-0166/09-0167

(Cons.); Nicor Gas Docket No. 04-0779; and in the previous Ameren rate case Docket Nos. 06-0070/06-0071/06-0072 (Cons.). (Staff Ex. 3.0, pp. 3-6; Staff Ex. 21.0, pp. 4-8)

The Company attempted to distinguish the current case from the prior cases by presenting an analysis that purports to determine the amount of OPEB liability that has been recovered in rates. That analysis applied test year amounts to customer billing information in between rate cases. (Ameren Ex. 2.4) However, this analysis is nothing more than an exercise in single-issue ratemaking; it assumes a single component of the revenue requirement remains the same and is not offset by changes in other components of the revenue requirement in between each rate case. The analysis is flawed because each revenue requirement that formed the basis of prior rates must be regarded as a whole and it is neither possible nor proper to go back in time and disaggregate prior base rates by line item to determine how much has been recovered for each element of the revenue requirement. That is, after rates are established, they are presumed adequate to allow a utility an opportunity to recover its costs, including a return on rate base. When rates are no longer adequate to do this, a utility may request a general increase in rates. However during the time those rates were effective, some expenses likely increased, while others may have declined. Therefore, it is not possible to state with certainty exactly how much of any particular expense was recovered through base rates. Rather, if the expense was reflected in the revenue requirement in previous rate cases, it is presumed that recovery was adequate to cover costs until new rates were approved. (Staff Ex. 3.0, p. 5)

During cross-examination of Staff witness Ms. Pearce, the Company challenged the truth of this well-established ratemaking concept, referencing the ten-year electric rate freeze that was legislatively mandated for the period 1997 through 2006. Ms.

Pearce acknowledged that a rate freeze had occurred for that period of time. (Tr., p. 119, September 12, 2011) However, the rate freeze only affected bundled electricity rates for customers taking service under bundled rates. Electric delivery service rates were not frozen, nor were utilities prohibited from seeking general rate increases for natural gas service.

Additionally, the Company asked Ms. Pearce the following question during cross-examination:

> "Just to be clear, during the 1997 to 2000 period, an electric utility could not file for a general rate increase even if there was a significant increase in an expense, is that correct?"

Ms. Pearce responded that she understood that to be the impact of the legislation at that time. (Tr., p. 120, September 12, 2011) For the record however, it is noteworthy that the rate freeze did not have the limiting impact implied in the carefully-worded cross-examination questions asked of Ms. Pearce. In fact, the three utilities that now comprise AIC—CIPS, CILCO and IP—did seek and obtain increases in both delivery service rates (as permitted by law) and natural gas rates during the period 1997 through 2006. (Examples of petitions for increases in delivery services tariffs ("DST") include Docket Nos. 00-0802 – AmerenCIPS DST; 01-0432 – Illinois Power Company (predecessor to AmerenIP) DST; and, 01-0637 – Central Illinois Light Company (predecessor to AmerenCILCO) DST. Examples of requests for a general increase in natural gas rates include Docket Nos. 02-0837 – Central Illinois Light Company (predecessor to Ameren CILCO); 03-0008, Central Illinois Public Service Company (predecessor to AmerenCIPS); and 04-0476 – Illinois Power Company (predecessor to AmerenIP).) Moreover, concurrent with the statutory electric rate freeze, other legislative changes were enacted to mitigate the impact of the rate freeze on electric utilities. Examples include transactions that no longer required Commission approval pursuant to Section 16-111(g) of the Act, including reorganizations, plant retirements, transfer of generating assets to affiliates, use of accelerated depreciation rates, and changes to the original cost of a utility's assets.

The Company's attempt to rely on the rate freeze as the basis for its treatment of the OPEB liability illustrates the futility of any attempt to go back in time and determine with specificity exactly how much was recovered through then-existing rates for a particular cost. Rather, the rates in effect at the time must be presumed to have been adequate. As the Company's own Exhibit 2.4 reflects, the costs of OPEB have been included in rates for many years. The Company should not now be allowed to have it both ways by reflecting costs in the revenue requirement over a lengthy period of time and subsequently complaining that they were not adequately compensated. This treatment could be viewed as retroactive ratemaking as well as single-issue ratemaking. Approval of such treatment could open the door for any utility to present an "analysis" of a given cost, claiming that it had not been fully recovered over some period of time, including multiple decades, and seeking to recover such amounts now and in the future. At the end of a rate case the record is marked "Heard and Taken" and no further evidence may be presented. Staff avers that the evidentiary record has been long closed for the cases cited and the period of time preceding the instant rate case proceeding. The treatment of the OPEB liability sought by the Company runs counter not only to well-established principles of ratemaking, but also to well-established principles of law.

In rebuttal testimony, Ms. Pearce agreed with the assertion of AG/CUB witness Mr. David Effron regarding this issue. (Staff Ex. 21.0, pp. 6 – 7) Specifically, she quoted an excerpt of his direct testimony as follows:

> To the extent that the cumulative accruals are greater than the actual cash disbursements, the Company will have accrued liabilities for OPEB. Thus, the accrued liabilities represent the expenses accrued in excess of actual payments for OPEB. (AG/CUB Ex. 1.0, p. 4)

Finally, Ms. Pearce noted that her adjustment reduces rate base for the projected average 2012 accrued OPEB liability that remains **after** the 2011 AIC contribution of $100 million, described by AIC witnesses and reflected in the Company's response to AG-DJE 3.19 Attach, line 4, column (c). As Ms. Pearce explained, this response demonstrates that even after the additional 2011 contribution from AIC, the Company projects an OPEB liability will remain for the 2012 test year. This liability represents expenses accrued in excess of actual payments; therefore, it is a proper reduction of rate base. (Staff Ex. 21.0, p. 7)

5. Accumulated Provision for Injuries and Damages

The Commission should accept Staff's recommended adjustment to reduce rate base by the amount of Accumulated Provision for Injuries and Damages ("APID") as shown in ICC Staff Exhibit 22.0R2, Schedule 22.02. The APID represents previously expensed costs (expense accruals) recovered from ratepayers that have accumulated over time on the balance sheet. These funds represent a source of cost free capital for the Company which entitles ratepayers to the benefit of a rate base deduction. The Company agrees with Staff's position in this respect. In his Rebuttal Testimony, Mr. Stafford explains:

> …it would be logical for these utilities to propose a rate base deduction if the expense accruals giving rise to this liability were included in operating expense in rates and in turn funded by ratepayers. Under that approach, ratepayers would have provided a source of cost free capital and would be entitled to the benefit of a rate base deduction. (Ameren Ex. 22.0, p. 23)

The point of contention between Staff and the Company is whether or not the dollars which fund the APID have been recovered from ratepayers.

The Company argues that ratepayers have not funded the APID because the Company in this and prior rate cases normalized the test year injuries and damages ("I&D") expense using an average of payouts rather than the more volatile and fluctuating expense accruals. (Ameren Ex. 40.0, p. 15) The test year expense for I&D is the test year expense for I&D regardless of the method used to estimate it. The Company's test years have included I&D expense, from which the APID has been accumulated.

Furthermore, application of the Company's argument to the facts demonstrates that ratepayers have funded a balance greater than the APID. Mr. Stafford indicates in his Surrebuttal Testimony that the normalization adjustment has occurred in each rate case dating back to Docket Nos. 06-0070 et al. (Cons.). (Ameren Ex. 22.0, p. 16) However, in each of the last two cases, the overall adjustment increased the I&D expense rather than decreasing it. Thus, the Company's adjustments have allowed it to recover more, not less, than the expense accruals necessary to fund the APID. Therefore, the Company's argument is erroneous and should be dismissed by the Commission.

6. PSUP Awards

The Commission should accept Staff's proposed adjustment to remove capitalized costs of this incentive stock award program because the program aligns the interests of employees and shareholders and there is no demonstrated benefit for ratepayers. (Staff Ex. 3.0, p. 18)

The PSUP awards the right to receive a share of Ameren stock assuming certain performance criteria are achieved. The PSUP aligns with shareholder interests; is competitive with market practice; promotes stock ownership; allows an employee to share in all success created for shareholders; measures Ameren against external peers; and creates long-term focus with its three-year vesting and performance period and an additional two-year vested holdback period. The actual number of shares earned varies based on Ameren's 2008-2010 total shareholder return ("TSR"). TSR is a function of the stock price and dividends. As this description indicates, the PSUP basically rewards the employee for the Company's financial performance and aligns the interests of employees with shareholders. Arguably, Ameren shareholders benefit from AIC rate increases. Additionally, the Company has not demonstrated that this incentive program provides any direct benefit to AIC ratepayers, beyond the incentive for employees to stay with Ameren that is created by the relatively longer vesting period. (Staff Ex. 3.0, pp. 18-21)

Due to fact the Company has not demonstrated that this incentive program provides any direct benefit to ratepayers, these costs should be removed from the 2012 test year revenue requirement. Additionally, the PSUP is based on financial targets like earnings per share ("EPS"). According to the PSUP program concept described in the Company's response to ICC Staff DR BAP-15.01, Attach 3, p. 3 of 8, 2008 PSUP Design Specifications:

> The actual number of share units earned will vary from 0% to 200% of target, based on Ameren's 2008-2010 total shareholder return ("TSR") relative to a utility peer group and on continued employment during 2008-2010.
>
> If Ameren's EPS covers its current dividend of $2.54 during each of 2008, 2009 and 2010, a minimum of 30% of a target award will be earned, regardless of TSR performance versus the peer group. If EPS falls below the dividend as measured at the beginning of the cycle but TSR performance is above the 30th percentile, the program will pay out according to the scale. If TSR is negative over 2008-2010, the plan is capped at 100% of target of relative performance.
>
> Once earned, share units continue to rise and fall in value with Ameren stock price during 2011 and 2012, at which point they are paid out in Ameren stock. Participants cannot vote share units or transfer them until they are paid out. Final payment of earned and vested share units is made even if the participant has left Ameren unless there has been a termination for Cause. (Staff Ex. 3.0, pp. 19 – 20)

Financial incentives like net income and EPS goals create a circular incentive in which rate increases help achieve the financial goals of the incentive program, thereby driving costs higher while providing little or no benefit to ratepayers. (*Id.*)

The Commission has a well-established standard for assessing recovery of incentive compensation costs. In Docket Nos. 09-0306 through 09-0311 (Cons.) the Commission reiterated the standard as follows:

> With regard to Staff's proposal to disallow costs that it believes have not been shown to result in net benefits to ratepayers, it is true that the Commission requires a finding that incentive compensation programs are beneficial to ratepayers before they can be reflected in rates. Whether one labels the benefit as a "tangible benefit" or a "net benefit" is immaterial. The bottom line is that ratepayers must receive an overall benefit from an incentive compensation plan if they are to be expected to pay for (a portion of) it. If no net benefit is realized by ratepayers upon the attainment of the plan goal, there is no reason for ratepayers to contribute funds encouraging AIU's employees to reach that goal.
>
> (Docket Nos. 09-0306/09-0311 (Cons.), Order, April 29, 2010, p. 83)

Costs associated with the PSUP are not necessary for the provision of utility service, nor did the Company demonstrate that they provide direct ratepayer benefits; therefore, these costs should be disallowed in their entirety. (Staff Ex. 3.0, p. 21)

In rebuttal testimony, Company witness Ms. Bauer conceded that the PSUP contains financial goals that must be met; however, she contended the PSUP still provides a benefit to Illinois ratepayers by providing an incentive for AIC employees to focus on long-term success and to stay with the organization. She asserted that customers derive benefit as management becomes more efficient and effective. (Ameren Ex. 27.0, pp. 4 - 5) According to Ms. Bauer, the financial incentives also benefit customers by encouraging cost management and cost control. Finally, she argued that strong financial performance enhances the Company's ability to invest in and strengthen AIC's electric and gas infrastructure, thereby enhancing system reliability. (*Id.*, p. 5) Although she contended full recovery would be proper and correct, Ms. Bauer proposed an equal sharing of PSUP costs between shareholders and ratepayers. (*Id.*, pp. 2-3) She explained that the Commission should consider the benefits to both ratepayers and shareholders, even where financial metrics are the basis for an incentive program like the PSUP. (*Id.*)

Staff asserts that although the PSUP may provide some tangential ratepayer benefits as described by Ms. Bauer, this plan is designed primarily to benefit shareholders, which is why the AIC employees are compensated with shares of Ameren stock instead of cash. Because shareholders are the primary beneficiaries of the PSUP, they should bear the cost. In support of this position, Staff cites Docket No. 05-0597 in which the Commission found that the portion of Commonwealth Edison's ("ComEd") incentive compensation plan that was based on an EPS metric should not be recovered through rates (Docket No. 05-0597, Order at 96, July 26, 2006) because the primary beneficiaries of increased earnings per share are shareholders, not ratepayers. The Commission noted that in spite of ComEd's assertion that the entire plan funding was dependent on "customer satisfaction", as measured by some customer survey benchmark, the Commission was not convinced that the link between performance was strong enough to warrant recovery of incentive payments for meeting financial goals. (Staff Ex. 21.0, pp. 14-15)

On appeal, the Appellate Court noted that the Commission ruled that ComEd did not demonstrate a sufficient nexus between the EPS portion of the incentive compensation plan and a benefit to ratepayers. The Appellate Court noted that ComEd's compensation expert witness had testified that incentive plans benefit everyone, including customers, because as "productivity rises, more attention is paid to cost control and more focus is given to customer service." The Company also asserted that a financially healthy utility can obtain needed financing at a lower cost, which would lower customer costs. At oral argument, the order notes the Company suggested the incentive plan benefited ratepayers by attracting good employees that raised the level of service customers receive. The Appellate Court concluded that such a benefit is too remote. (Docket No. 05-0597, Appellate Order, pp. 12 – 13, September 17, 2009) (Staff Ex. 21.0, p. 15)

The types of tangential customer benefits described in ComEd Docket No. 05-0597 above are similar to those described by Ms. Bauer in her arguments for the PSUP. Accordingly, Staff maintains the position that all costs related to the PSUP should be removed from the revenue requirement in the instant proceeding. (*Id.)*

D. Recommended Rate Base

Based on the rate bases for the electric and gas utilities originally proposed by AIC for each of its rate zones and Staff's proposed adjustments to those rate bases as summarized above, the electric utility rate base proposed by Staff for rate zone 1 is $412,092,000, for rate zone 2 is $244,843,000, and for rate zone 3 is $1,336,267,000. The gas utility rate base proposed by Staff for rate zone 1 is $222,900,000, for rate zone 2 is $179,543,000, and for rate zone 3 is $542,245,000. The rate bases are summarized as follows:

Staff Recommended Rate Bases
(In Thousands)

1. Electric

Description (a)	Rate Zone 1 (CIPS) (b)	Rate Zone 2 (CILCO) (c)	Rate Zone 3 (IP) (d)
Gross Plant in Service	$1,497,660	$920,172	$2,579,005
Accumulated Depreciation	(888,321)	(552,988)	(898,343)
Net Plant	609,339	367,184	1,680,662
Additions to Rate Base			
Plant Held for Future Use	373	-	-
Cash Working Capital	4,059	3,133	4,325
Materials & Supplies Inventory	9,380	4,130	16,785
	-	-	-
Deductions From Rate Base			
Customer Advances	(7,377)	(4,511)	(128)
Accumulated Deferred Income Taxes	(186,801)	(113,299)	(334,143)
Customer Deposits	(11,399)	(5,710)	(15,306)
OPEB Liability	(1,066)	(6,182)	(4,397)
Budget Payment Plans	(562)	(784)	(1,030)
Accum. Provision for Injuries &	(3,854)	882	(10,501)

Damages			
Rate Base	$412,092	$244,843	$1,336,267

2. Gas

Description	Rate Zone 1 (CIPS)	Rate Zone 2 (CILCO)	Rate Zone 3 (IP)
Gross Plant in Service	$424,732	$566,099	$1,059,509
Accumulated Depreciation	(204,643)	(384,745)	(521,857)
Net Plant	220,089	181,354	537,652
Additions to Rate Base			
Cash Working Capital	4,851	6,242	9,516
Materials & Supplies Inventory	24,176	30,793	64,162
Plant Held for Future Use	-	-	-
	-	-	-
Deductions From Rate Base			
Accumulated Deferred Income Taxes	(20,790)	(27,831)	(5,366)
Customer Advances	(1,919)	(1,771)	(50,003)
Customer Deposits	(1,916)	(3,018)	(4,246)
OPEB Liability	(636)	(2,764)	(1,966)
Budget Payment Plans	-	(222)	(292)
Accum. Provision for Injuries & Damages	(955)	(3,240)	(7,212)
Rate Base	$222,900	$179,543	$542,245

III. OPERATING REVENUES AND EXPENSES

A. Overview

B. Resolved Issues

1. Storm Expenses

In its initial filing, Ameren proposed normalizing its storm costs over a 5 year period, 2005-2009, for a total normalized cost of $14,607,621. (Ameren Ex. 9.0E, p. 8; Ameren Ex. 9.2, pp. 1-2) Staff witness Elsaid recommended an adjustment to normalize storm costs over a 6 year period for a total normalized cost of $12,551,502. (ICC Staff Exhibit 11.0R, p. 12) In her Rebuttal Testimony, Ms. Elsaid presented several examples utilizing different normalization time periods and resulting calculations of normalized storm costs. (Staff Ex. 27.0, pp. 7-8) Staff and the Company are now in agreement on the use of a 6 ½ year normalization period from 2005 through June 2011, with a total normalized cost of $13.65 million, as indicated by Staff's response to Data Request AIC-Staff 20.01. (Ameren Ex. 46.5)

2. Wages and Salaries and Employee Benefits

Staff proposed a six percent reduction of forecasted 2012 test year wages and salaries and employee benefits based on information contained in the MIPO Study attached to the direct testimony of Company witness Mr. James Mazurek. (Staff Ex. 3.0, pp. 11 – 13; Schedules 3.03 and 3.04)

Based on information provided by various Company witnesses in rebuttal testimony, Staff withdrew this adjustment in rebuttal testimony. (Staff Ex. 21.0, p. 16)

3. Investment Tax Credits

4. Rate Case Expense

Staff witness Tolsdorf proposed an adjustment to remove from the revenue requirement certain merger costs that were included with rate case expense. (Staff Ex. 22.0R2, p. 10) The Company has removed the questioned costs from rate case expense and included them with merger costs. (Ameren Ex. 22.0, p.12)

Accordingly, Staff recommends that the Commission make the following finding in its Final Order:

> The Commission finds that the amounts of compensation for attorneys and technical experts to prepare and litigate this proceeding, as adjusted by Staff, are just and reasonable pursuant to Section 9-229 of the Public Utilities Act (220 ILCS 5/9-229).

5. Social and Service Club Dues

Staff witness Tolsdorf proposed an adjustment to remove from the revenue requirement all social and service club dues. (Staff Ex. 4.0, p.7) Upon further discovery, it was determined that dues associated with the Electric Power Research Institute (EPRI) were incorrectly classified by AIC as social and service club dues rather than industry association dues. The Company proposed in rebuttal testimony to remove all social and service club dues excluding the EPRI dues. (Ameren Ex. 22.0, p. 25) Staff accepts the Company's proposed adjustment as shown on Ameren Exhibit 22.12, Schedule 1, page 1.

6. Lobbying Costs

Staff witness Tolsdorf proposed an adjustment to remove from the revenue requirement certain lobbying expenses specifically disallowed by Section 9-224 of the Public Utilities Act ("Act"). (Staff Ex. 4.0, p. 8) Staff's adjustment was accepted by AIC in rebuttal testimony. (Ameren Ex. 22.0, p. 7)

7. Athletic Events Expense

Staff witness Tolsdorf proposed an adjustment to remove from the revenue requirement certain expenditures for athletic events, including the cost of tickets to professional baseball and hockey games. (Staff Ex. 4.0, p. 11) Staff's adjustment was accepted by AIC in rebuttal testimony. (Ameren Ex. 22.0, p. 7)

8. Liberty Substation Painting Expense

Staff witness Hathhorn proposed adjustments to reduce AIC's operating expenses to normalize the cost of substation painting since AIC acknowledged that its test year forecast reflects an accelerated schedule for 2012, and AIC plans to return to a normal, ongoing level of maintenance in 2013. (Staff Ex. 2.0R, p. 12 and Sch. 2.05) The Company accepted Staff's adjustments and included them in its rebuttal revenue requirements. (Ameren Ex. 22.0, p. 7)

9. NESC Expense

AIC initially proposed to disallow 87% of its estimated test year National Electrical Safety Code ("NESC") violation correction costs because the Commission disallowed that percentage in its Final Order in Docket Nos. 09-0306 to 09-0311 (Cons.). (AIC Ex. 2.0E. pp. 26, 28) Staff witness Rockrohr recommended that the

Commission instead disallow 100% of AIC's test year costs for correcting NESC violations. (Staff Ex. 10.0, p. 2)

Mr. Rockrohr explained that it was inappropriate for AIC to base its future 2012 NESC disallowance amount on Ameren's historic 2008 NESC work because the types and quantities of NESC violation corrections that AIC will perform in 2012 and later years will be different from the NESC work Ameren performed in 2008. Ameren's NESC Corrective Action Plan demonstrates that virtually all of AIC's NESC violation correction work in 2012 and 2013 will be associated with repairing overhead guys and down guys that are not properly insulated or grounded. These NESC violations associated with overhead guys and down guys exist because the utility initially constructed the facilities incorrectly. In Ameren's prior two rate cases, the Commission determined that Ameren should not recover these costs from ratepayers. (Staff Ex. 10.0, pp. 6-8)

Mr. Rockrohr recommended reductions of $328,247 from AIC's proposed operating expenses and $174,483 from AIC's proposed plant in service, as well as associated adjustments to depreciation expense, accumulated depreciation, and accumulated deferred income taxes. AIC accepted Mr. Rockrohr's recommended adjustments in rebuttal testimony. (AIC Ex. 22.0, p. 7; AIC Ex. 26.0, p. 5)

10. Company Use of Fuels

Staff witness Jones proposed an adjustment to decrease the cost of fuels used by AIC for its own purposes. The adjustment reflects the updated test year cost of gas as provided by AIC. (Staff Ex. 6.0, p. 3) AIC accepted Ms. Jones' adjustment. (Ameren Ex. 35.0 (Rev.), p. 2)

11. Power Smart Pricing

Staff witness Tolsdorf proposed an adjustment to remove from the revenue requirement data processing costs for the Power Smart Pricing program that are recovered through Rider PSP. (Staff Ex. 4.0, p. 12) The Company stated that this was an oversight and Staff's adjustment was accepted by AIC in rebuttal testimony. (Ameren Ex. 22.0, p. 7)

12. Hazardous Materials Adjustment Clause (HMAC) Base Rate

Staff witness Tolsdorf testified that the HMAC Base Amount included in the Rate Zone 3 (formerly Ameren IP) revenue requirement is $234,690. (Staff Ex. 22.0R2, p.16) The HMAC Base Amount as defined in Rider HMAC Hazardous Materials Adjustment Clause is the amount of HMAC Costs reflected in the test year in the Company's most recent electric rate Commission Order.9 This amount is needed to determine the amount to be withdrawn or deposited annually into the HMAC Cost Fund. The Company accepted Staff's proposed HMAC Base Amount in Mr. Stafford's Surrebuttal testimony. (Ameren Ex. 40.0, p. 24) Accordingly, Staff recommends that the Commission make the following finding in its Final Order:

> The Commission finds that the amount of HMAC Costs reflected in the test year electric revenue requirement for Rate Zone 3 (formerly Ameren IP) is $234,690.

13. Supply Procurement Adjustment

Staff proposed an adjustment to the SPA to remove pension costs for production employees from the AIC-Electric revenue requirement. This adjustment reduced costs for the three electric rate zones by $168,000 in total. (Staff Ex. 21.0, Schedule 21.04) In

[9] Ill. C.C. No.1, Original Sheet No. 47.003. This Rider applies to AmerenIP electric only.

surrebuttal testimony, Company witness Mr. Stafford accepted Staff's proposed adjustment to the SPA. (Ameren Ex. 40.0, p. 5)

C. Contested Issues

1. Uncollectibles Expense

Pursuant to Sections 16-111.8(a) and 19-145 of the PUA, the Commission may, in a proceeding to review a general rate case, order the Company to prospectively switch from using the actual uncollectible amount set forth in Account 904 to using net write-offs in the determination of the amount to recover through its Riders EUA ("Electric Uncollectible Adjustment") and GUA ("Gas Uncollectible Adjustment"), provided that net write-offs are also used to determine the utility's uncollectible amount in rates. In the event the Commission requires such a change, it shall be made effective at the beginning of the first full calendar year after the new rates approved in such proceeding are first placed in effect. (Staff Ex. 3.0, p. 10)

Staff witness Pearce recommended that the Commission should order the Company to prospectively switch from using the actual uncollectible amount in Account 904 to using net write-offs as a percentage of revenues. Staff's rationale is that the balance of Account 904, uncollectibles expense, fluctuates with changes to the allowance for doubtful accounts. The allowance for doubtful accounts is based on estimates of uncollectible accounts. A switch to the net write-off method would ensure that the calculation of incremental uncollectible expense recoverable through Rider EUA and Rider GUA is based on actual accounts written-off and recovered instead of estimated amounts. Actual information is preferable to estimates since it is more accurate and should be used whenever available. (*Id.*, pp. 6 - 7) Staff further asserts that Sections 16-111.8(a) and 19-145 of the Act support Staff's proposal. (*Id.*, pp. 9 - 10) The Commission's Order in Docket No. 10-0517 (Proposal 1, Order at 3) supports Staff's position that rates should be determined by individual electric and gas rate zone. (Staff Ex. 21.0, p. 10)

Staff witness Pearce also proposed a change to the Gross Revenue Conversion Factor ("GRCF") to reflect the uncollectibles percentage for each respective electric and gas rate zone based on a six-year average of net write-offs as a percentage of revenues. (Staff Ex. 3.0, p. 6) It is necessary to change the GRCF because the adjustment to uncollectibles expense only adjusts the uncollectible expense associated with revenues at present rates. There will also be an impact on uncollectible costs associated with the change in revenues that result from this docket. The GRCF adjusts uncollectible expense for the change in revenues at present rates. (*Id.*, pp. 8 – 9) Therefore, Staff reflected the GRCF based on the percentage of uncollectible revenues for each respective electric and gas rate zone, as presented in Staff's revenue requirement. (Staff Ex. 1.0, Schedule 1.06 for each rate zone) Staff further noted that the final uncollectibles percentages approved by the Commission in the instant proceeding should be used to update the uncollectibles adjustment in the Electric Power Supply SCA and Rider S for PGA supply, and all other tariffs in which the Commission-approved uncollectibles rate is a factor. (Staff Ex. 3.0, p. 8)

The Company opposed Staff's recommendations to switch from using Account 904 to the net write-off method (Ameren Ex. 21.0, p. 24) and to base the percentage on a six-year average. Instead, the Company proposed to use an average of the balance of Account 904 for the three most recent calendar years 2008 through 2010. (*Id.*, p. 2)

Additionally, the Company rejected the calculation of a separate percentage for each electric and gas rate zone, instead proposing to use a single percentage for electric uncollectibles and a single percentage for gas uncollectibles (*Id.*, p. 9).

In Staff rebuttal testimony, Ms. Pearce accepted the Company's proposal to use a three-year average based on calendar years 2008 through 2010. However, she maintained her proposal that individual uncollectibles percentages should be calculated for each respective gas and electric rate zone and her recommendation of a switch to the net write-off method. (Staff Ex. 21.0, p. 9)

2. Charitable Contributions

The Commission should accept Staff's adjustment to charitable contributions which sets the 2012 test year amount at 2% above the Company's projected budget for 2011. The Company has proposed an unreasonable 64% increase to the 2011 charitable contributions budget. The Company asserts that the reason for its level of contributions in 2011 was:

> Due to budget constraints from the most recent [rate] order, the charitable contributions budget was reduced for 2011. The budget for 2012 returned contributions to normal levels. (Ameren's response to Staff DR ST-2.02, Staff Ex. 4.0, p. 6)
>
> In 2011, we simply were unable to budget for contributions to the level that we wanted to due to economic and budgetary conditions. (Ameren Ex. 28.0, p. 4)

In Docket Nos. 09-0306 et al (Cons.), to which Ameren refers, Staff accepted and the Commission approved the Company's rebuttal proposal of approximately $883,000 for charitable contributions. (Docket Nos. 09-0306 et al. (Cons.), Final Order, pp. 68-69)(Docket Nos. 09-0306 et al. (Cons.), Ameren Ex. 29.13) The Company's charitable contributions budget for 2011 is approximately $1.2 million. The Company's charitable contribution budget for the 2012 test year is approximately $2 million. The Company has proposed that its test year amount of approximately $2 million is reasonable because they have every intention of spending that amount. Company witness Mr. Ogden states in his Surrebuttal testimony:

> The Company specifically budgeted $2 million dollars for charitable contributions for 2012 with the good faith intention of spending that amount during 2012. (Ameren Ex. 53.0, p. 4)

Mr. Ogden further stated in his Surrebuttal Testimony:

> …he (Mr. Tolsdorf) did not challenge the expected contributions to any one charity as being too much or too little, or that the nature of any charity is inappropriate. As my rebuttal testimony established, the recipients listed all operate within AIC's territory and are well established organizations. (Ameren Ex. 53.0, p. 3)

The Company's intention to spend money is not justification in and of itself for ratepayer recovery. Furthermore, Staff is not challenging any specific proposed contribution but rather the aggregate amount of contributions which the ratepayers are required to support. In Business and Professional People for the Public Interest v. Illinois Commerce Commission,10 the Illinois Supreme Court said:

> …we believe that the Commission must determine the reasonableness of the amount of contributions based on the total contributions rather than on an individualized basis. There are numerous charitable organizations worthy of Edison's support. If Edison were to make a reasonable donation to each of these organizations, the aggregate total of the donations could very easily exceed a reasonable amount. (146 Ill.2d at 255, 585 N.E.2d at 1067, 166 Ill. Dec. 10 at 45)

Charitable contributions are a discretionary expense and the Company has provided no justification for such a significant percentage increase from its 2011 budget or from the amount authorized by the Commission in the most recent rate case.

[10] 146 Ill.2d 175, 585 N.E.2d 1032, 166 Ill. Dec. 10

3. Injuries and Damages Expense

The Commission should accept Staff's adjustment to normalize Injuries and Damages expense ("I&D") for the entire expense rather than just a portion of the expense. (ICC Staff Exhibit 22.0R2, p. 3) The Company proposes to normalize only the expense accruals portion of the I&D expense. (Ameren Ex. 22.0, p. 22) However, the remaining portion of the I&D expense has fluctuated greatly over the time period from 2006 through 2010 and appears to be just as "highly volatile" as the expense accruals over the same time period. The main goal of normalizing any expense for ratemaking purposes is to include in the revenue requirement the most representative amount of expense for the test year. The Company has provided no evidence which would explain why its projected test year I&D expense would be significantly higher than the inflation adjusted five year average. Mr. Stafford filed a supplemental testimony adjustment which indicated that AIC had incorrectly allocated some I&D expenses for the forecasted test year between gas and electric. A review of Mr. Stafford's rebuttal revenue requirement schedules indicates that the adjustments mentioned in the supplemental testimony are not reflected in the revenue requirement schedules. The uncertainty introduced from the Company's accounting errors and failure to reflect the corrections in its proposed revenue requirement are a further reason Staff's position of normalizing the entire amount of I&D should be accepted.

4. Merger Costs

Staff has withdrawn its objection to merger costs initially removed on Staff Ex. 3.0, Schedule 3.06, and this issue is no longer considered contested between Staff and the Company. (Staff Ex. 3.0, pp. 14 – 18; Schedule 3.06; Staff Ex. 21.0, pp. 16 – 18; Schedule 21.03)

5. State Income Tax Expense - Regulatory Asset

Staff witness Hathhorn proposed adjustments to reduce AIC's electric and gas operating expenses for the Company's deferred state income tax ("SIT") expense from 2011. The Company proposes to record a regulatory asset for the increase in SIT for calendar year 2011. The regulatory asset represents deferred expenses incurred outside of the test year and is, therefore, unreasonable to include in the 2012 test year. (Staff Ex. 2.0R, p. 4 and Staff Ex. 20.0, p. 4 and Sch. 20.01) AG/CUB witness Effron and IIEC witness Michael P. Gorman also proposed to remove the SIT Regulatory Asset amortization from operating expenses. (AG/CUB Ex. 1.0, pp. 25 – 26; IIEC Ex. 3.0, pp. 71-72)

<u>The Company's Proposal is Inappropriate Single Issue Ratemaking and Contrary to Test Year Rules</u>

The Company's proposal involves a single cost from outside the test year. The proposal raises the specter of single issue rate making since it involves including non-test year expenses into the revenue requirement in a case with a future test year. The Commission "must examine all elements of the revenue requirement formula to determine the interaction and overall impact any change will have on the utility's revenue requirement." *Citizens Utility Board v. Illinois Commerce Comm'n*, 166 Ill. 2d 111, 138 (1995). Clearly, deferral of operating expenses for later recovery would violate the Commission's test year rules as established in *Business and Professional People for the Public Interest v. Illinois Commerce Commission*, 146 Ill. 2d 175 (1991) ("*BPI II*"), by allowing recovery of these operating expenses outside of the test year:

> In order to accurately determine the utility's revenue requirement, the Commission established filing requirements under which a utility must present its rate data in accordance with a proposed one-year test year. The purpose of the test-year rule is to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year.
>
> *BPI II,* 146 Ill. 2d 175, 240-241.

(Staff Ex. 2.0R, p. 6)

In Docket No. 98-0895 (Order, March 15, 2000), the Commission denied an application by Citizens Utilities Company of Illinois to defer and amortize costs associated with remediation of Y2K issues. The Commission determined that the Y2K costs were operating expenses. The Commission found:

> If this deferral is allowed, the Applicant may offset revenue in a future rate filing against these expenses. Under general rate making principles, only expenses incurred during the test year can be used to offset revenue accrued during that year.
>
> Although, the expenses appear to be reasonable and made in the public interest, they are not sufficiently large, or sufficiently unique, to justify special accounting treatment. The requested deferral would improperly match expenses from a non-test year with revenues from a test year. The requested deferral is contrary to the ratemaking principle requiring that expenses be recognized in the year in which they are incurred.
>
> Docket No. 98-0895, Order, Section IV.

In this Order, the Commission cited *BPI II* which found that recovery of operating expenses outside of the test year violates test year principles. (*BPI II*, pp. 240-241) The Commission's Order also cited Docket No. 93-0408, a rulemaking proceeding regarding the deferral of costs (Order, October 19, 1994):

> The Commission has previously recognized the applicability of BPI II to the question of deferral of operating expenses in ratemaking in Docket 93-0408. That recognition is dispositive of the issue in this proceeding.
>
> Docket No. 98-0895, Order, Section IV.

In Docket No. 93-0408, the Commission accepted the utilities' definition of deferred costs as "items of expense or savings that would ordinarily be recognized as such in a given period, but which would be recognized at a future time." (Docket No. 93-0408, Order, p. 2) (Staff Ex. 2.0R, pp. 6-7)

The Change in Corporate Income Tax Rate Created No Special Obligation of the State Nor Granted the Commission Authority to Ignore its Test Year Rules

Staff stated that the fact that this increased expense was caused by a change in the state income tax rate does not change the fact that it is an out-of-test year period increase, no different than if the Company's wages were higher in 2011 than in its last rate case. The Company argued in surrebuttal testimony that "the State is not meeting its obligation" if the Commission does not provide rate recovery. (Ameren Ex. 39.0, p. 4) However, there is no provision in the state income tax legislation directing the Commission to make utility companies whole or make utility ratepayers pay for all increased tax liability in between rate cases. Rather, the income tax rate for corporations was simply raised to 7.0% from 4.8% without discussion of the impact on Illinois utilities nor any change in Commission authority regarding such additional SIT. (35 ILCS 5/201 (b)(8) and (10))[11] Further, other expenses may be decreasing enough to offset the magnitude of the SIT increase, which is why operating expenses are analyzed as a whole and why allowed rate recovery is generally based upon a test year examining all changes in the company's financial position, not just isolated increases. Moreover, deferring and amortizing an operating expense causes revenue and expenses to be improperly matched as one year's expenses would be netted against a different year's revenue. (Staff Ex. 2.0R, p. 5)

[11] The replacement tax rate remained at 2.5%. 35 ILCS 5/201(d)

The Company also argues that it had no opportunity to alter utility rates before the change in tax rate went into effect. (Ameren Ex. 21.0 (Rev.), p. 4) If the Company had selected a 2010 historical test year, the 2010 state income tax expense would have been restated based upon the increased state income tax rate as a known and measurable change incurred within the test year period as defined in 83 Ill. Code 287.40. No deferral or regulatory asset would have been created since the test year would already include the 2011 increased SIT at issue here. (Staff Ex. 20.0, p. 5)

The court rulings and Commission orders on the subject of rate recoverability of deferred operating expenses are discussed above. They are not new. They began as far back as 1991, with ICC orders and decisions issued in 1994, 1995 and 2000 consistent with such court rulings. (Staff Ex. 2.0R pp. 6-7) Therefore, the Company should have been aware of the consequences of the rate recoverability of its increased 2011 SIT expense. (Staff Ex. 20.0, p. 4)

<u>The Company Misrepresents the Commission's Past Practice Regarding Tax Rate Changes and Staff's Adjustment is neither Unfair nor Asymmetrical</u>

The Company argues that "[a]ll AIC is seeking here is regulatory treatment that is symmetrical with the Commission's prior practice regarding a change in tax rates." (Ameren Ex. 21.0 (Rev.), p. 4, lines 73-74) The Company misrepresents the Commission's past practice (Ameren Ex. 39.0, p. 4) and asks this Commission to not follow its established test year rules. The Commission cannot simply look to its orders from the regulatory treatment of the Tax Reform Act of 1986 ("TRA") and use symmetrical reasoning in order to determine the appropriate rate treatment of the Company's request. The TRA orders for the Company's former operating utilities show that the Commission required a revenue requirement analysis for each utility prior to any ratemaking change taking place. (Staff Group Cross Ex. 13) In other words, there was no simple, standard Commission practice as the Company's testimony implies. In addition, not all utilities changed their rates due to the tax decrease, including the former CILCO and CIPS' gas operations. (*Id*.)

The Company also argues that "one of the Commission's important roles is to assure that rates fairly reflect the interests of utilities and customers alike" and that "[a] policy that always favors customers is not symmetrical, fair or reasonable…"(Ameren Ex. 21.0 (Rev.), p. 4, lines 81-84) Any implication that Staff adjustments "always favor[] customers" is wrong. For example, Staff's direct testimony included a correction to the Company's accumulated deferred income taxes that increased the Company's rate base and, therefore, was a benefit to the Company, not ratepayers. (See Staff Ex. 2.0R, Sch. 2.03R) Staff's position on the Company's request to recover a deferred operating expense outside of the test year is not based upon the result of the proposal, but rather the controlling guidance of the test year rules and the aforementioned court rulings. (Staff Ex. 20.0, p. 7) The Commission should adopt Staff's adjustments.

6. PSUP Awards

In response to Staff's proposed disallowance of 100% of PSUP Awards costs (Staff Ex. 21.0, Schedule 21.03), Company witness Ms. Bauer contended that full recovery of the PSUP Awards costs would be proper and correct; however, she proposed an equal sharing of PSUP costs between shareholders and ratepayers. (Ameren Ex. 27.0, pp. 2-3) She explained that the Commission should consider the benefits to both ratepayers and shareholders, even where financial metrics are the basis for an incentive program like the PSUP. (*Id.*)

Staff asserts that although the PSUP may provide some tangential ratepayer benefits as described by Ms. Bauer, this plan is designed primarily to benefit shareholders, which is why the AIC employees are compensated with shares of Ameren stock instead of cash. Because shareholders are the primary beneficiaries of the PSUP, they should bear the cost. The Commission should accept Staff's proposed adjustment to disallow the remaining 50% portion of the costs related to the PSUP because they do not provide ratepayer benefit. (Staff Ex. 3.0, pp. 18 -21; Staff Ex. 21.0, pp. 13 - 15) This issue is addressed in Rate Base Section II. C. 6.

7. Electric Distribution O&M Expense

Ameren proposes to spend $230,540,000 towards operation and maintenance ("O&M") during the test year. This amount represents a $50,642,000 or a 28.15% increase in 2012 O&M spending compared to 2011 proposed O&M spending, and an increase of $40,268,000 or 21.16% in comparison to 2009 actual O&M spending. Based on the information that Ameren provided on its O&M spending from 2005 through 2012, Mr. Rashid concluded that Ameren spent more O&M dollars in the years that are designated as test years in previous rate cases (2006, 2008, and 2012) than it did in non-test years.[12] Ameren's data also showed a substantial decrease in O&M spending during non-test years.

[12] See Staff Ex. 12.0, page 13, Figure 2.

In his direct testimony, Mr. Rashid requested that Ameren explain its O&M spending pattern. Mr. Rashid also requested that Ameren address what harm Ameren has done to its electricity delivery system by under spending during non-test years.[13]

In its rebuttal testimony, Ameren indicated that the main driver of variation in O&M spending for the years 2005 through 2008 was storm expenses. Ameren attributed the significant variation in O&M spending between 2009 and 2012 to incremental circuit maintenance, incremental substation maintenance, incremental vegetation management activities, incremental Liberty Audit expenses, and 2% inflation from 2009 through 2012.[14] Mr. Rashid considered the information that Ameren provided in its rebuttal testimony and concluded that Ameren's explanation regarding its O&M spending between 2006 and 2008 might be valid.[15]

Regarding its O&M spending form 2009 to 2012, Ameren indicated that incremental O&M spending related to the implementation of Liberty Audit recommendations, circuit inspections, and substation inspections in 2009, 2010, and 2011 was $0.[16] The overall O&M spending has been decreasing for three consecutive years starting in 2009. Ameren witness Mr. Nelson described actions that Ameren took in response to the Commission's order in Ameren's latest rate case after stating that Ameren "determined that the revenues granted by the Order were inadequate."[17] Mr. Nelson indicated that Ameren "significantly reduced its 2010 operating and capital budgets."[18] Mr. Rashid expressed concerns about Ameren's decision to reduce its O&M spending based on its determination that the Commission did not grant it

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[13] See *Id.*, page 14.
[14] See Ameren Ex. 29.0, pages 10 and 11.
[15] Staff Ex. 28.0, page 7.
[16] See *Id.,* Attachment A.
[17] See Ameren Exhibit 1.0E, page 15.
[18] See *Id.*

"adequate" revenues. Ameren decided to reduce its O&M spending for three consecutive years in spite of statements by three Ameren witnesses indicating that doing so would have negative repercussions on Ameren's system reliability in the long term.[19] Ameren failed to explain whether, or to what extent, the levels of Ameren's O&M spending for 2009, 2010, and 2011 affected the reliability of its distribution system.

Ameren's decreased spending on maintenance of its electric distribution system because of its determination that the revenue granted by the Commission in the last rate case was "inadequate," is dangerous. Cancelation or deferment of the implementation of activities designed to maintain or improve the reliability of Ameren's distribution system may cause more outages and more expensive mitigation efforts in the future.[20]

Mr. Rashid recommended that Ameren be required to maintain consistent O&M spending levels regardless of the outcome of the Commission's order. In cross-examination, Mr. Rashid explained that the phrase "maintain consistent O&M spending" does not necessarily mean that Ameren should spend the same amount of money from year to year. Rather, that phrase suggests that Ameren should continue spending towards programs that it implements to maintain or improve the reliability of its system regardless of the outcome of this or any other rate case proceedings.[21] Mr. Rashid further indicated that he has no opinion on the amount of dollars that Ameren should spend on its O&M activities.[22] In his rebuttal testimony, Mr. Rashid stated, "Ameren

[19] See Staff Ex. 28.0, pages 8 and 9.
[20] *Id.,* pp. 10 and 11.
[21] See Tr., September 12, 2011, page 154.
[22] See *Id.*, page 163.

should base changes in annual O&M budgets on its operational needs and should be able to explain those needs and the changes in its budget to the Commission."[23]

Depending on the outcome of this rate case, Ameren may decide to continue the approach of cancelling or deferring projects pertinent to O&M that are vital to the reliability of its distribution system. Therefore, Staff recommends that the Commission include language ordering Ameren to maintain consistent O&M spending levels in its final order in this docket.[24]

D. Recommended Operating Income/Revenue Requirement

Based on the operating expense statements for the electric and gas utilities originally proposed by AIC for each of its rate zones and Staff's proposed adjustments to operating revenues and expenses as summarized above, the total electric utility delivery services net operating income proposed by Staff for rate zone 1 is $35,644,000, for rate zone 2 is $21,178,000, and for rate zone 3 is $115,580,000. The total gas utility net operating income proposed by Staff for rate zone 1 is $18,333,000, for rate zone 2 is $14,767,000, and for rate zone 3 is $44,659,000. The operating expense statements are summarized as follows:

Staff Recommended Operating Income/Revenue Requirements
(In Thousands)

1. Electric

Description	Rate Zone 1 (CIPS)	Rate Zone 2 (CILCO)	Rate Zone 3 (IP)
Electric Operating Revenues	$241,730	$135,851	$442,034

[23] See Staff Ex. 28.0, page 11.
[24] *Id.,* page 11.

Other Miscellaneous Revenues	13,422	5,469	16,459
Total Operating Revenue	255,152	141,320	458,493
Uncollectible Accounts	2,193	1,048	4,199
Distribution Expenses	97,128	35,010	110,597
Cust. Service & Inform. Exp	15,002	9,088	25,424
Admin. & General Expenses	32,475	34,110	63,740
Depreciation & Amort. Expenses	52,973	29,642	84,613
Taxes Other Than Income	5,237	2,638	7,456
Total Operating Expense Before Income Taxes	205,008	111,536	296,029
State Income Tax	3,384	2,008	10,957
Federal Income Tax	11,116	6,598	35,927
Total Operating Expenses	219,508	120,142	342,913
NET OPERATING INCOME	$35,644	$21,178	$115,580

2. Gas

Description	Rate Zone 1 (CIPS)	Rate Zone 2 (CILCO)	Rate Zone 3 (IP)
Gas Service Revenues	$75,956	$76,796	$171,316
Other Miscellaneous Revenues	1,096	1,313	2,732
Total Operating Revenue	77,052	78,109	174,048
Uncollectible Accounts	858	944	2,673
Production Expenses	580	504	676
Storage, Term., and Proc. Exp.	1,617	1,946	3,959
Transmission Expenses	1,551	1,160	3,308
Distribution Expenses	18,489	16,147	34,682
Cust. Accounts, Service & Sales	7,287	6,581	15,792
Admin. & General Expenses	9,954	17,215	24,961
Depreciation & Amort. Expenses	7,594	9,775	17,335
Taxes Other Than Income	3,567	3,289	8,460
Total Operating Expense			

Before Income Taxes	51,497	57,561	111,846
State Income Tax	1,679	1,350	4,085
Federal Income Tax	5,543	4,431	13,458
Total Operating Expenses	58,719	63,342	129,389
NET OPERATING INCOME	$18,333	$14,767	$44,659

IV. COST OF CAPITAL/RATE OF RETURN

A. Overview

Staff witness Phipps recommends an 8.650% rate of return on rate base for AIC's electric delivery services, which incorporates the 9.72% rate of return on common equity that Staff witness Freetly recommends. Ms. Phipps also recommends an 8.225% rate of return on rate base for AIC's gas delivery services, which incorporates the 8.90% rate of return that Ms. Freetly recommends. (Staff Ex. 24.0, Sch. 24.01)

The overall cost of capital for a public utility equals the sum of the costs of the components of the capital structure (*i.e.*, debt, preferred stock and common equity) after weighting each by its proportion to total capital. Under the traditional regulatory model, ratepayer and shareholder interests are balanced when the Commission authorizes a rate of return on rate base equal to the public utility's overall cost of capital, as long as that overall cost of capital is not unnecessarily expensive. In authorizing a rate of return on rate base equal to the overall cost of capital, all costs of service are assumed reasonable and accurately measured, including the costs and balances of the components of the capital structure. If unreasonable costs continue to be incurred, or if any reasonable cost of service component is measured inaccurately, then the allowed rate of return on rate base will not balance ratepayer and investor interests. (Staff Ex. 7.0, p. 2)

Staff's proposed capital structure for AIC comprises 0.19% short-term debt, 46.28% long-term debt, 1.72% preferred stock and 51.82% common equity. (Staff Ex. 24.0, Schedule 24.01) Staff compared AIC's 46% debt ratio to the Moody's Investors Service ("Moody's") benchmark total debt to total capital ratio for Baa-rated regulated electric and gas utilities, which range from 45% - 55%. According to Moody's, an obligor rated 'Baa' is considered medium-grade and is subject to moderate credit risk, which suggests that the Company's average 2012 capital structure is commensurate with a strong but not excessive degree of financial strength. (Staff Ex. 7.0, pp. 7-8)

B. Resolved Issues and Immaterial Differences – Cost of Capital/ Capital Structure

1. Remaining CWIP accruing AFUDC Adjustment

Ms. Phipps explained that the Commission's formula for calculating short-term debt assumes that any construction work in progress ("CWIP") not funded by short-term debt is funded proportionately by the remaining sources of capital (*i.e.*, long-term debt, preferred stock and common equity). Therefore, Ms. Phipps adjusted the monthly short-term debt balances to remove the portion of short-term debt reflected in the calculation of allowance for funds used during construction ("AFUDC") and allocated $90,522,710 of remaining amount of CWIP accruing an AFUDC according to the proportion of total long-term capital that each long-term capital component represents. (Staff Ex. 7.0, pp. 3-4) Given long-term debt, preferred stock, and common equity compose 46.36%, 1.72% and 51.91% of AIC's long-term capital, respectively, Ms. Phipps subtracted 46.36% of $90,522,710, or $41,969,281, from the long-term debt balance; 1.72% of $90,522,710, or $1,560,004, from the preferred stock balance; and 51.91% of $90,522,710, or $46,993,425, from the common equity balance. (Staff Ex. 24.0, p. 2) The Company does not oppose this adjustment. (Ameren Ex. 24.0, p. 2)

2. Preferred Stock Balance

There is no material difference between the average 2012 preferred stock balance of $59,158,692 that Staff recommends and the Company's proposed balance of $59,194,837. (Staff Ex. 24.0, Schedule 24.01; Ameren Ex. 24.2, p. 2)

3. Short-Term Debt Balance

Staff and the Company agree that AIC's average 2012 short-term debt balance equals $6,473,198. (Staff Ex. 24.0, Schedule 24.01; Ameren Ex. 24.2, p. 2)

4. Long-Term Debt Balance

There is no material difference between the average 2012 long-term debt balance of $1,591,564,788 that Staff recommends and the Company's proposed balance of $1,591,759,083. (Staff Ex. 24.0, Schedule 24.01; Ameren Ex. 24.2, p. 2)

5. Common Equity Balance (other than Purchase Accounting/Goodwill)

Both Staff and the Company adjusted the average 2012 common equity balance to reflect their proposed rate increases and removed the amount of common equity already incorporated into the AFUDC calculation.

6. Cost of Preferred Stock

Staff and the Company agree that the average 2012 embedded cost of preferred stock equals 4.98%. (Staff Ex. 7.0, p. 15)

C. Contested Issues

1. Common Equity Balance

a. Purchase Accounting/Goodwill

The Company's average 2012 common equity balance excludes approximately $344 million of purchase accounting adjustments reflected in Account 114 as of September 30, 2010. (Ameren Ex. 4.0, p. 17) Staff avers the Company's proposed purchase accounting adjustments reflect bookkeeping entries to Account 114 that do not affect AIC's common equity balance; therefore, Staff proposes to remove the goodwill balance in lieu of the Company's purchase accounting adjustment balance to avoid including in rates any purchase accounting adjustments that are not appropriate for ratemaking purposes. (Staff Ex. 7.0, pp. 5-6)

Staff recommends that the Commission reject the Company's proposed purchase accounting adjustments because they could not be verified. First, those purchase accounting adjustments reflect unrelated amortization of account 219, Accumulated Other Comprehensive Income. Furthermore, push down accounting entries must be finalized within one year of the closing date of reorganization. Once finalized, purchase accounting adjustments should decrease ratably until the end of the applicable amortization period. Nevertheless, AIC expects the purchase accounting adjustment to increase from 2010 to 2011, then decrease from 2011 to 2012. In contrast, the Company expects its goodwill balance will remain constant in 2011 and 2012. (Staff Ex. 24.0, pp. 2-3; Ameren Ex. 22.0,

p. 40, footnote 5) Moreover, the common equity balance that AIC presents to its investors excludes goodwill instead of purchase accounting adjustments. (Tr., September 13, 2011, pp. 235-236)

Further, without explanation, the Company dropped $63 million in income-related purchase accounting adjustments from its current rate case. In the 2007 Illinois Power rate cases, the Company made two purchase accounting-related adjustments to Illinois Power's balance of common equity: the first adjustment subtracted $155 million of "goodwill net of purchase accounting adjustments;" the second adjustment subtracted $63 million of "income generated from … purchase accounting." (Tr., September 13, 2011, pp. 238-242) This is especially troubling given the difference between the Company's $344 million purchase accounting adjustment and $411 million goodwill balance equals approximately $63 million, meaning a similar retained earnings adjustment in the instant case would have resulted in purchase accounting adjustments that approximate the Company's goodwill balance.

When asked whether both of the adjustments in the 2007 rate case – *i.e.,* the $155 million that equals goodwill net of purchase accounting, plus the $63 million reduction to retained earnings – would be subtracted from the common equity balance as purchase accounting adjustments, Company witness Mr. Ronald Stafford testified:

> [The $63 million] would have been an adjustment made after the IP acquisition by Ameren to reflect the absence of paying out common dividends for the retained earnings associated specifically with the purchase accounting impact on the income statement… [the $63 million] was specifically related to retain[ed] earnings from income generated from push down accounting or purchase accounting. Until such time as the [retained earnings] have been fully paid out in common dividends, the company made that adjustment. (Tr., September 13, 2011, pp. 239-241)

Granted, purchase accounting is required for financial reporting purposes, and the Company must reverse the effects of purchase accounting for regulatory purposes. (Ameren Ex. 22.0, p. 38) Yet, dividends do not represent a reversal of purchase accounting adjustments to net income, as Mr. Stafford claims. Rather, companies declare dividends out of earnings as a whole, rather than a particular type of earnings; the Uniform System of Accounts ("USOA") defines retained earnings as "the accumulated net income of the utility less distribution to stockholders and transfers to other capital accounts." (83 Ill. Adm. Code 415 Definition 33. Retained Earnings) Moreover, the USOA provides no instruction for tracing dividends to a particular source of utility income. (83 Ill. Adm. Code 415, Instruction for Account 438 Dividends declared – common stock) Company witness Martin testified that it is almost impossible to pinpoint exactly how cash is used. (Tr., September 13, 2011, p. 220) Finally, in Docket No. 04-0294, the Commission lifted pre-existing restrictions on IP's common dividend payments. (Order, Docket No. 04-0294, September 22, 2004, pp. 13 and 53-54) Given IP was not prohibited from paying dividends following the acquisition by Ameren Corp., it is not clear why any "unpaid" common dividend would still remain when Illinois Power filed its 2007 rate case almost three years following its acquisition by Ameren. Thus, the Company's explanation for its exclusion of the 2007 rate case adjustment to retained earnings from the current rate cases should be rejected because it is contrary to the Commission's rules and its Order in Docket No. 04-0294 allowing Illinois Power to recommence dividend payments.

For all the foregoing reasons, Staff cannot verify the Company's proposed purchase accounting adjustments, which may result in an overstatement of the Company's common equity balance for ratemaking purposes. In contrast, Ms. Phipps' adjustment would avoid including in rates any purchase accounting adjustments that are not appropriate for ratemaking purposes. (Staff Ex. 7.0, pp. 5-6) Therefore, the Commission should adopt Staff's proposed common equity balance for AIC, which excludes $411 million goodwill.

2. Cost of Short-Term Debt

a. Forecast 2012 Short-Term Debt Interest Rate

The Company's projected short-term debt balances comprise 100% bank loans, which are made on a 30-day basis, in which case the interest rate on those bank loans will equal a 30-day LIBOR rate, plus a 2.05% margin that is based on AIC's senior unsecured credit ratings of Baa3/BBB- from Moody's and S&P. As such, Staff recommends a 2.24% cost of short-term debt for AIC that equals the current 0.19% one-month LIBOR rate, plus a 2.05% margin. (Staff Ex. 7.0, pp. 8-9)

The Company's proposed short-term debt rate is problematic for two reasons. First, the Company used the projected 3-month LIBOR rate to estimate the cost of 30-day bank loans, which will overstate the Company's actual cost of short-term debt because interest rates typically rise as the time horizon for the investment lengthens. Second, AIC's proposed short-term debt rate is based on a forecasted interest rate instead of a current, observable interest rate. The Company argues that, "It is reasonable to rely on interest rate forecasts, which are based on expert analysis, for forward test year purposes." (Ameren Ex. 24.0, pp. 4 and 16) However, accurately forecasting interest rates is problematic. Moreover, the accuracy of a forecast diminishes as the time horizon lengthens. For example, a comparison of the March 2007 Blue Chip Economic Indicators projections for the annual average for 10-year U.S. Treasury bonds for years 2009 and

2010 over estimated the actual annual average 10-year U.S. Treasury bond yield by 1.9 percentage points. (Staff Ex. 24.0, pp. 4-5) Therefore, the Commission should adopt Staff's proposed short-term debt rate, which is based on current, observable interest rates for the same time horizon as the expected short-term bank loans.

b. Credit Facility Commitment Fees

Ameren established three credit facilities in September 2010: the $800 million Ameren Illinois credit facility (the "Illinois Facility," which covers AIC and Ameren), the $800 million Ameren Missouri credit facility, and the $500 million Ameren Energy Generating Company ("Genco") credit facility. Ms. Phipps calculated one-time arrangement and upfront fees for Ameren Illinois to maintain its bank lines of credit and annualized the amount over the three-year period for which the credit facility will be effective, as well as annual fees, to arrive at her recommendation to add 8 basis points to AIC's overall cost of capital for bank commitment fees. (Staff Ex. 7.0, pp. 9-11)

The contested issue regarding bank commitment fees relates to the amount of upfront fees. Section 9-230 of the PUA prohibits including in a utility's allowed rate of return any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies. (220 ILCS 5/9-230) Specifically, bank commitment fees vary from 0.25% to 0.875% of the amount of each lender's aggregated commitments to the three credit facilities, and the Company's response to ICC Staff data request RMP 1.04 states, "[u]pfront fees were paid as a percentage of each bank's credit commitment…banks that committed less than $75 million received 25 basis points." The highest commitment by a single lender to the Illinois Facility was $47.62 million. Therefore, the fee schedule indicates that each lender would have charged AIC 25 basis points if the upfront fee had been assessed against the commitment to the Illinois Facility alone. Ms. Phipps calculated upfront fees of $2,000,000 (*i.e.*, 0.0025 x $800 million). Moreover, Ameren's ability to borrow up to $300 million under the Illinois Facility effectively reduces the Ameren Illinois sub-limit to $500 million (or 62.5% of the $800 million facility). Therefore, Ms. Phipps calculated $1,250,000 of upfront fees is recoverable for ratemaking purposes pursuant to Section 9-230 of the Act. (Staff Ex. 24.0, p. 13)

AIC alleges that Ms. Phipps misinterpreted data provided by the Company regarding upfront fees. Further, AIC alleges that it separately negotiated the upfront fees for the Illinois Facility. (Ameren Ex. 24.0, p. 4) The facts show otherwise. First, the invoice setting forth the closing fees covers all three credit facilities. (Ameren Ex. 24.2) Second, the Illinois, Missouri, and Genco Upfront fees are identical percentages of the total commitment to those facilities (*i.e.*, 0.665%). (Ameren Ex. 24.2) Third, excepting the names of the Ameren companies listed, the Arrangers Fee Letters are identical for the three facilities. (Ameren Ex. 24.3) Fourth, the individual bank commitments to the Illinois and Missouri facilities are identical and each bank's commitment to Genco is exactly 62.5% of that bank's commitment to the Illinois and Missouri facilities. (Staff Ex. 24.0, Attachment 2, p. 2) Fifth, since the Commitment Fee Rates are all multiples of 0.5 basis points (Staff Ex. 24.0, Attachment 1, p. 4) and each bank commitment is a multiple of $5 million (Staff Ex. 24.0, Attachment 2, p. 2), each bank received a commitment fee that is a multiple of $250 (*i.e.*, 0.005% x $5 million). Nonetheless, the upfront fees to the three facilities are all calculated to the nearest penny (*i.e.*, $3,325,892.86 to Genco and $5,321,428.57 to both Ameren Illinois and Missouri). (See Ameren Ex. 24.2.) Calculating upfront fees totaling millions of dollars, down to the penny, in amounts exactly proportionate to three facilities entered at that time, is consistent with allocating upfront fees negotiated jointly rather than separately negotiating upfront fees for the Illinois Facility. If the three facilities had been negotiated independently, some variation in these fee and individual bank commitment amounts per total commitment should exist, but there is none. (Staff Ex. 24.0, pp. 14-15)

The Company claims that AIC's affiliation with Genco does not result in any increases in Illinois Facility commitment fees. The Company also claims that banks are willing to accept a lower commitment fee rate for a larger combined transaction and that economies of scale would have resulted in lower bank commitment fees. (Ameren Ex. 24.0, p. 6) To the contrary, under the terms of the Illinois Facility, the upfront fee rates increase as commitment amounts increase. As such, aggregating commitments under the Illinois, Missouri and Genco credit facilities results in higher upfront fees than would result from calculating upfront fees based on the commitments under each individual credit facility. Furthermore, there are no economies of scale associated with a larger credit facility given that, under the terms of the Illinois Facility, upfront fee rates increase as commitment amounts increase. (Staff Ex. 24.0, pp. 15-16)

The Company argues it concluded the Illinois Facility fees were reasonable and prudent because its commitment fee rate was consistent with rates paid by other utilities during 2010 and provides Ameren Ex. 24.5 in support of this argument. (Ameren Ex. 24.0, pp 5-6) The Company's argument should be disregarded on two levels. On the factual level, the Company's argument implies the data for credit facilities provided in Ameren Ex. 24.5 are similar to the Illinois Facility. However, Ameren Ex. 24.5 does not reveal the fee rate for bank commitments of similar magnitude to those in the Illinois Facility (*i.e.*, $50 million or lower). More importantly, the Company's argument misses the legal issue. The adjustment to the upfront fees is not a matter of reasonableness or prudence. Rather, the issue falls under Section 9-230 of the Act because the commitment fee rate is progressive (*i.e.*, escalating) and determined on the basis of aggregate bank commitments under the Illinois, Missouri and Genco Facilities. In other words, the fee rate AIC pays is a direct function of its affiliation with non-utility and unregulated companies. The greater the commitment to the Missouri and Genco facilities, the higher upfront fee rate AIC pays.

Illinois courts have specifically addressed this issue regarding the interpretation of Section 9-230 of the PUA. The 2nd District Appellate Court, in the case of *Illinois Bell Telephone Co. v. Illinois Commerce Comm'n*, 283 Ill. App. 3d 188, 207, 218 Ill. Dec. 598, 669 N.E.2d. 919 (1996), held that "In section 9-230, the legislature used the word "any" to modify its prohibition of considering incremental risk or increased cost of capital in determining a reasonable ROR. This usage removes all discretion from the Commission. Section 9-230 does not allow the Commission to consider what portion of a utility's increased risk or cost of capital caused by affiliation is "reasonable" and therefore should be born by the utility's ratepayers; the legislature has determined that any increase whatsoever must be excluded from the ROR determination. *It is impermissible for the Commission to substitute its reasonableness standard for the legislature's absolute standard.*" (emphasis added) As succinctly put by the Court, it is not permissible for the Commission to substitute its reasonableness standard for the legislature's absolute standard. Therefore, AIC's arguments that the Illinois Facility fees were reasonable and prudent is irrelevant to its recovery of these fees. Therefore, as a matter of Law, the Commission must adopt Staff's recommendation that AIC's cost of capital for bank commitment fees equals 8 basis points rather than the 10 basis point adder the Company seeks.

3. Cost of Long-Term Debt

Staff recommends a 7.44% embedded cost of long-term debt for the Company. (Staff Ex. 24.0, Schedules 24.01 and 24.02). AIC disagrees with Staff's adjustments to (1) the coupon rate for the Company's expected October 2012 bond issuance; (2) reduce the principal amount of the $400 million 9.75% bonds that IP issued in October 2008 by $50 million; and, (3) reduce the interest rate for the 8.875% bonds that CILCO issued in December 2008 to 6.76%.

a. Forecast 2012 Long-Term Debt Interest Rate

AIC expects to issue $150 million bonds during October 2012 to replace the $150 million bonds that matured in June 2011. (Ameren Ex. 4.0, p. 8) Staff recommends a 4.4% interest rate for those bonds, which equals the June 3, 2011, 3.11% 10-year U.S. Treasury bond yield, plus the current 129 basis points spread over treasuries for 10-year Baa1/BBB+ rated utility bonds. (Staff Ex. 7.0, p. 13) In contrast, AIC's proposed 5.4% interest rate adds a similar spread over treasuries to the average 2012 and 2013 consensus forecasts for 10-year U.S. Treasury bonds (3.8% and 4.5%, respectively), which is problematic for the reasons discussed hereafter.

AIC's proposed rate for the October 2012 debt issuance should be rejected because it reflects a forecasted interest rate instead of a current, observable interest rate. The Company argues, "It is reasonable to rely on interest rate forecasts, which are based on expert analysis, for forward test year purposes." However, as discussed under Short Term Debt, accurately forecasting interest rates is problematic and, the accuracy of a forecast diminishes as the time horizon lengthens.

AIC argues that Ms. Phipps' current U.S. Treasury yield is "inappropriate" and "unreasonably conservative." AIC contends that 10-year Treasury yields are near historic lows and "the prevailing opinion among economist is that yields will rise in the near term." (Ameren Ex. 24.0, p. 15) Yet, 10-year U.S. Treasury bond yields have fallen since the date of Staff's analysis. On September 6, 2011, the 10-year U.S. Treasury bond yield equaled 2.02% (Tr., September 13, 2011, p. 206), which is much lower than the 3.11% U.S. Treasury bond yield that Staff used to derive its 4.4% coupon rate estimate, and even the 3.1% yield that professional forecasters predicted just one month earlier. (Tr., September 13, 2011, pp. 199-202) Furthermore, Blue Chip Financial Forecast, the Company's primary source for interest rate forecasts (Tr., September 13, 2011, pp. 195-196 and 204), has lowered its projections since the January 2011 publication that the Company relied upon for its proposed long-term debt rate. Specifically, as shown below, the August 2011 Blue Chip Financial Forecast estimates 10-year T-bond yields that are 40 basis points (0.40%) lower than the January 2011 Blue Chip Financial Forecast.

10-Year U.S. Treasury Bond Yield Forecasts as published by Blue Chip Financial Forecasts		
	January 1, 2011	August 1, 2011
3rd Quarter 2011	3.5%	3.1%
4th Quarter 2011	3.7%	3.3%
1st Quarter 2012	3.9%	3.5%
2nd Quarter 2012	4.1%	3.7%
Source: Tr., September 13, 2011, pp. 199-202.		

The effect of the decrease in interest rates can be seen in a recent bond issuance by Commonwealth Edison Company ("ComEd'). In August 2011, ComEd issued $350 million 10-year bonds with a 3.4% coupon rate. (Tr., September 13, 2011, pp. 192-194)

Thus, during the next three to four months, when rates set at the conclusion of this proceeding will become effective, the market rate of interest on ten-year, BBB+/Baa1-rated utility bonds would have to rise about one percentage point to equal Staff's proposed 4.4% rate and two percentage points to reach AIC's proposed 5.4% rate. Even if interest rates are at historic lows, the Company's forecast would require a large increase over a very short period, which is not plausible.

For all the foregoing reasons, the Commission should adopt Staff's proposed coupon rate for the bonds that AIC expects to issue in October 2012.

b. AmerenIP October 2008 Debt Issuance

For the purpose of calculating the embedded cost of long-term debt (but not for the purpose of calculating the balance of long-term debt), Staff recommends reducing the balance of the $400 million 9.75% bonds that AmerenIP issued during October 2008 to $350 million. This adjustment is based on the Order from Docket Nos. 09-0306 et al. in which the Commission concluded that AmerenIP issued $50 million more long-term debt than required for its utility operations during October 2008. Specifically, the Commission Order states:

> It appears to the Commission that AmerenIP issued more long-term debt than required for AmerenIP's utility operation, especially at a time when AmerenCIPS was relying on low cost money pool funds, contributed in part by AmerenIP, rather than resorting to the issuance of costly long-term debt. The Commission agrees with Staff that AmerenIP's proposal would unnecessarily burden ratepayers with $50 million in excess debt at a relatively high interest rate of 9.75%. the Commission will, therefore, adopt Staff proposed long-term debt balance for AmerenIP for the purposes of this proceeding. (Order, Docket Nos. 09-0306 et al. (Cons.), April 29, 2010, p. 143)

For the current docket, Ms. Phipps used the resulting calculated embedded cost of long-term debt, 7.39%, as the coupon rate for the remaining $50 million of AmerenIP's October

2008 bonds. Consequently, ICC Staff Exhibit 7.0, Schedule 7.02, "Embedded Cost of Long-Term Debt," splits the October 2008 bonds into two entries. The first entry shows $350 million of bonds issued at the actual interest rate of 9.75%. The second entry shows $50 million of bonds issued at the overall embedded cost of debt rate of 7.39%. Ms. Phipps explained that removing $50 million in 9.75% bonds from AIC's long-term debt for the purpose of calculating the balance of long-term debt would have the perverse result of a disallowance that increased AIC's rate of return on rate base due to a shift in the capital structure weights from lower cost debt to higher cost common equity. (Staff Ex. 7.0, pp. 12-13)

Therefore, the Commission should adopt Staff's adjustment, which removes $50 million of costly long-term debt from AIC's cost of capital that the Commission found AmerenIP did not require for utility operations in Docket Nos. 09-0306 et al.

c. AmerenCILCO December 2008 Debt Issuance

Ms. Phipps determined that CILCO's affiliation with both CILCORP and AmerenEnergy Resources Generating Company ("AERG") had adversely affected CILCO's cost of capital in December 2008 based on rating agencies' reports that indicated CILCO's business risk profile reflected its affiliation with AERG and CILCORP. Thus, Staff removed the incremental effect of both of those non-utility affiliates from CILCO's authorized rate of return in accordance with Section 9-230 of the PUA. (Staff Ex. 24.0, p. 10)

Specifically, using the S&P rating methodology, Ms. Phipps changed CILCO's business risk profile from "Satisfactory," which S&P stated reflected CILCO's non-regulated businesses, to "Strong," which was the less risky business risk profile that S&P

assigned to CIPS and IP. Similarly, using the Moody's rating methodology, Ms. Phipps changed CILCO's business risk profile from "Medium" (the typical business risk profile for integrated utilities) to "Low" (the typical business risk profile for less risky transmission and distribution utilities). (Staff Ex. 7.0, pp. 13-14; Tr., September 13, 2011, p. 221) Ms. Phipps concluded that CILCO's implied credit rating would increase by two notches (from A1 to Aa2) if its business risk profile were "Low" instead of "Medium." Given CILCO's actual senior secured debt rating from Moody's was Baa2 in December 2008, Ms. Phipps concluded that CILCO's secured debt rating would have been two notches higher, or A3, if CILCO's non-utility affiliates had not increased its business risk profile.[25] Therefore, Ms. Phipps recommends a 6.76% coupon rate for the bonds CILCO issued in December 2008, which reflects the average yield for A3/A- rated bonds during the same measurement period. (Staff Ex. 24.0, pp. 6-8)

In Docket Nos. 09-0306 et al., the Commission adopted this adjustment by Staff, stating:

> …there has been an increased cost to AmerenCILCO for long-term debt due to the presence of its unregulated affiliates CILCORP and AERG…Therefore, the Commission will adopt Staff's proposed cost of long-term debt rate…, as to do otherwise would penalize ratepayers for the presence of AmerenCILCO's unregulated affiliates, contrary to the provisions of Section 9-230 of the Act. (Order, Docket Nos. 09-0306 et al., April 29, 2010, pp. 150-151)

In the instant case, AIC mischaracterizes Staff's testimony when it alleges that Staff concluded that absent a single credit factor (*i.e.*, CILCO's ownership of AERG), CILCO's credit ratings would have been higher and its cost of debt would have been

[25] Note that this adjustment is relative to CILCO's actual senior secured credit rating in December 2008. A relative adjustment assumes the qualitative factors in a credit rating are unaffected. An absolute adjustment based on a direct application of CILCO's financial ratios to the Moody's "Low" business risk benchmarks would conclude that CILCO's senior secured credit rating would have been Aa2.

lower. (Ameren Ex. 24.0, pp. 8-9 and 13-14) To the contrary, as Ms. Phipps explained, both of CILCO's non-utility affiliates – CILCORP and AERG – affected CILCO's credit ratings. (Staff Ex. 24.0, p. 10)

AIC alleges that since Fitch Ratings lowered CILCO's credit rating in May 2010 and Moody's affirmed CILCO's Baa3 rating following the transfer of AERG to another Ameren subsidiary, that one could conclude CILCO's ownership of AERG did not adversely affect CILCO's credit ratings or increase CILCO's borrowing cost. (Ameren Ex. 4.0, pp. 14-15) First, the recent downgrade to CILCO's credit rating by Fitch Ratings does not warrant revisiting the interest rate adjustment for the bonds that CILCO issued during December 2008. Since the cost of fixed-rate debt is established at the time of issuance and does not adjust in response to changes in the market yield spreads or in the creditworthiness of the issuer, the coupon rate adjustment should be based on the facts at the time of the bond issuance. The adjustment should not be based on subsequent events. (Staff Ex. 24.0, p. 9)

Second, several factors contributed to the downgrade of CILCO's issuer default rating, which makes it impossible to separate the net effect of one factor from other factors. Specifically, Fitch Ratings acknowledged that the transfer of AERG lowered the business risk of CILCO and, at the same time it lowered CILCO's issuer default rating to BBB- from BBB, it affirmed the BBB- issuer default ratings of CIPS and IP. Fitch Ratings stated that commingling all the monies of CIPS, IP and CILCO supports equalization of the ratings given bondholders would share in a single pool of cash flow. Importantly, Fitch Ratings explained that CILCO's downgrade reflects the Commission's April 2010 rate order and the consolidation of CIPS, IP and CILCO, as well as management's plan to transfer AERG to an affiliate that owns other merchant generation assets. (Staff Ex. 7.0, pp. 14-15)

Finally, the Company argues, "...Ms. Phipps considered historical metrics that were not adjusted to exclude AERG's meaningful cash flows." (Ameren Ex. 24.0, p. 10) Ms. Phipps explained that AIC's characterization of AERG cash flows as "meaningful cash flow contributions" that provided "a significant positive impact on AmerenCILCO's creditworthiness" is based on an incomplete picture of AERG's effect on CILCO. As shown in the table below, in 2005, AERG's $5 million net loss had a negative effect on CILCO's consolidated net income and, in 2006, AERG's net income was slightly less than the contribution by CILCO's regulated Illinois segment. Furthermore, CILCO's credit rating was constrained by $210 million of long-term debt at its intermediate parent company CILCORP, which had significantly lower financial metrics on a consolidated basis than CILCO. CILCORP paid approximately $31 million interest expense annually from 2005-2008 in connection with its outstanding indebtedness. As the table below shows, AERG's net income totaled $135 million from 2005-2008. In comparison, CILCORP interest expense totaled $130 million. Moreover, AERG cash flows were volatile in comparison to CILCORP's interest requirements. In other words, CILCO was squeezed between AERG's higher operating risk and additional financial risk from CILCORP. In summary, much of AERG's cash flows merely replaced the cash needed to service CILCORP's debt. (Staff Ex. 24.0, pp. 11-12)

CILCO Net Income (Loss) and CILCORP Interest Expense (In millions)			
Year	inois Regulated Net Income	AERG Net Income	ILCORP Interest Expense
2008	$16	$52	$31
2007	$9	$65	$31
2006	$25	$23	$31
2005	$30	($5)	$37

For all the foregoing reasons, the Commission should apply the 6.76% coupon rate that Staff recommends to CILCO's December 2008 bond issuance in order to remove any incremental risk reflected in CILCO's business risk profile due to CILCORP and AERG, as required by Section 9-230 of the PUA.

4. Cost of Common Equity

a. Overview of Recommended Returns

The table below presents Staff witness Janis Freetly's estimates of the investor-required rates of return on common equity for the natural gas distribution and electric delivery service operations for AIC. (Staff Ex. 8.0, pp. 2 and 26-27 and Schedule 8.09)

	AIC	
	Gas	Electric
Sample DCF	8.63%	9.55%
Sample CAPM	9.31%	10.32%
Sample Average	8.97%	9.94%
Financial Risk Adjustment	0.09%	-0.06%
Uncollectibles Rider Adjustment	-0.16%	-0.16%
AIC Cost of Common Equity	8.90%	9.72%

Ms. Freetly measured the investor-required rate of return on common equity with the non-constant discounted cash flow ("DCF") and Capital Asset Pricing Model ("CAPM") analyses. For the natural gas distribution operations, Ms. Freetly applied those models to the same sample of eight local gas distribution companies utilized by AIC witness Robert Hevert. For the electric delivery service operations, Ms. Freetly applied those models to a sample of sixteen regulated electric utilities. (Staff Ex. 8.0, p. 3)

(i) DCF Analysis

DCF analysis assumes that the market value of common stock equals the present value of the expected stream of future dividend payments to the holders of that stock. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. The companies in Ms. Freetly's Gas and Electric samples pay dividends quarterly. Therefore, Ms. Freetly employed a multi-stage non-constant-growth DCF model that reflects a quarterly frequency in dividend payments. (*Id.*, p. 4-5)

Staff witness Freetly modeled three stages of dividend growth. For the first five years, Ms. Freetly used market-consensus expected growth rates published by Zacks Investment Research ("Zacks") and Reuters as of June 3, 2011. For the second stage, a transitional growth period that spans from the beginning of the sixth year through the end of the tenth year, Ms. Freetly used the average of the first- and third-stage growth rates. Finally, for the third, or "steady-state," growth stage, which commences at the end of the tenth year and is assumed to last into perpetuity, Ms. Freetly calculated a 4.8% expected long-term nominal overall economic growth rate beginning in 2021; that growth rate was calculated using the expected real growth rate (2.6%) based on the average of the Energy Information Administration's ("EIA") and Global Insight's long-term forecasts of real gross domestic product ("GDP"), and the expected inflation rate (2.5%) based on the difference between yields on U.S. Treasury bonds and U.S. Treasury Inflation-Protected Securities. She then combined the resulting 5.2% growth estimate with the 4.5% average nominal economic growth forecasted by EIA and Global Insight. (*Id.*, pp. 7-9)

The growth rate estimates were combined with the closing stock prices and dividend data as of June 3, 2011. Based on these growth assumptions, stock price, and dividend data, Ms. Freetly's DCF estimate of the cost of common equity was 8.63% for the Gas sample and 9.55% for the Electric sample. (*Id.*, p. 12)

(ii) Risk Premium Analysis

Staff witness Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. The CAPM requires the estimation of three parameters: the risk-free rate, beta, and the required rate of return on the market. For the risk-free rate parameter, Ms. Freetly considered the 0.04% yield on four-week U.S. Treasury bills and the 4.26% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of June 3, 2011. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.5% and 5.4%. Thus, Ms.

Freetly concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate. For the expected rate of return on the market parameter, Ms. Freetly conducted a DCF analysis on the firms composing the S&P 500 Index. That analysis estimated that the expected rate of return on the market equals 12.67%. Finally, for the beta parameter, Ms. Freetly combined adjusted betas from Value Line, Zacks, and a regression analysis. The average Value Line, Zacks, and regression beta estimates for the Gas sample were 0.66, 0.56, and 0.51, respectively. For the Electric sample, the average Value Line, Zacks, and regression beta estimates were 0.72, 0.73, and 0.69, respectively. The Value Line regression employs 259 weekly observations of stock return data regressed against the New York Stock Exchange ("NYSE") Composite Index. Both the regression beta and Zacks betas employ sixty monthly observations; however, while Zacks betas regress stock returns against the S&P 500 Index, the regression beta regresses stock returns against the NYSE Index. To avoid over-weighting the monthly data-based betas in comparison to the weekly data-based betas, Ms. Freetly averaged the Zacks and regression estimates. She then averaged that result with the Value Line beta, which produced a beta of 0.60 for the Gas Sample and 0.72 for the Electric sample. Inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 9.31% for the Gas sample and 10.32% for the Electric sample. (*Id.*, pp. 12-24)

(iii) Staff Cost of Common Equity Recommendation

Ms. Freetly estimated the investor required rate of return on common equity for the Gas sample of 8.97% by taking a simple average of the DCF-derived results (8.63%) and the risk-premium-derived results (9.31%). She then adjusted the Gas sample's investor required rate of return upward 9 basis points to reflect the higher financial risk of AIC relative to the Gas sample. Next, she adjusted the Company's cost of equity downward 16 basis points to reflect the reduction in risk associated with Rider GUA. Thus, the investor-required rate of return on common equity is 8.90% for the natural gas distribution operations of AIC. (*Id.*, p. 26)

To estimate the investor-required rate of return on common equity for the electric delivery service operations of the Company, Ms. Freetly first calculated the simple average of the DCF-derived results (9.55%) and the risk-premium derived results (10.32%) for the Electric sample, or 9.94%. Next, she adjusted the Electric sample's investor required rate of return downward 6 basis points to reflect the lower financial risk of AIC relative to the Electric sample. Next, she adjusted the Company's cost of equity downward an additional 16 basis points to reflect the reduction in risk associated with Rider EUA. Thus, the investor required rate of return on common equity is 9.72% for the electric delivery service operations of AIC. (*Id.*, pp. 26-27)

To assess the reasonableness of her ROE recommendations, Ms. Freetly compared her results to the yield on utility debt. As of the date of her analysis, the market required a 5.30% rate of return on less-risky A-rated utility long-term debt and a 5.81% rate of return on BBB-rated utility long-term debt. (Mr. Hevert acknowledged during cross-examination that the 30-year Treasury bond yield had dropped below 4% by mid- September, 2011. (Tr., September 14, 2011, p. 406))[26] In Ms. Freetly's judgment, the investor-required rate of return on common equity of 8.90% for the natural gas operations and 9.72% for the electric delivery service operations is reasonable in

[26] During cross, Mr. Hevert was asked what the current yield on 30-year T-bonds. He indicated that the yields were in the mid- to upper-3% range, depending on the day.

comparison to the observable rate of return that the market currently requires on utility long-term debt. (Staff Ex. 8.0, p. 25; Staff Ex. 25.0R, p. 16)

b. DCF Model Estimates

i. Proxy Groups

To select her sample for the electric delivery service operations, Ms. Freetly began with the list of electric utilities the Edison Electric Institute ("EEI") categorizes as Regulated since her return on common equity recommendation is for the regulated electric operations of AIC. Next, she eliminated the companies that were not assigned an industry classification code of 4911 or 4931 within Standard & Poor's ("S&P") Utility Compustat. Then, she removed companies that are or recently have been involved in mergers, acquisitions, or divestures. Next, she eliminated the regulated electric utilities with credit ratings from S&P in the BBB range (BBB+ to BBB-). Finally, she removed companies that did not pay dividends in the last four quarters and were not covered by the Value Line Investment Survey ("Value Line"). The remaining sixteen regulated electric utilities compose Ms. Freetly's Electric sample. (Staff Ex. 8.0, p. 3)

Ms. Freetly relied on the EEI "Regulated" designation in forming an electric sample for the purpose of estimating the investor-required rate of return on equity for the electric delivery service operations in the last two rate proceedings for the Ameren Illinois utilities. In the last two Ameren rate proceedings, Ameren witness' electric samples included electric utilities classified as "Regulated" and "Mostly Regulated" by EEI, electric utilities with greater than 50% of total assets in regulated operations. In both of those proceedings, Ms. Freetly narrowed that group to include only those electric utilities classified by EEI as "Regulated" since those electric utilities have 80% or more of total assets in regulated operations. In the 2007 Dockets, the Ameren Illinois utilities accepted Staff's investor-required rate of return recommendation, based on the sample of "Regulated" EEI electric utilities. In the 2009 Dockets, the Commission Order accepted Staff's DCF and CAPM methodologies which were performed on the sample of "Regulated" electric utilities. Hence, Ms. Freetly relied on that same criterion for selecting her Electric sample in this case. (Staff Ex. 25.0R, p. 3)

Mr. Hevert testified that it is more appropriate to screen companies based on the percentage of regulated operating income and revenues than the percentage of regulated assets, which was the basis for Staff's electric sample selection. (Ameren Ex. 23.0, p. 20) The cost of capital for a company equals the average cost of capital of the businesses in which it operates, weighted by the amount of capital invested in each business.[27] Thus, a company's primary line of business is better determined by where its capital is invested than by which segment produces the highest revenues. The percentage of revenues and operating income from regulated operations do not measure operating risk directly and in no was establish that companies that do not meet those criteria are not similar in risk to the target utility. Thus, the regulated revenue and operating income criteria at best provide limited support for the inclusion in a proxy sample of companies that meet those criteria; they do not invalidate the use of all other companies, as Mr. Hevert's argument implies. Finally the percentage of revenues and operating income from regulated operations are poor proxies for operating risk because they are heavily influenced by volatile energy prices. As energy prices change, a competitive energy subsidiary's revenues and profits can vary greatly, oscillating

[27] More generally, the cost of capital for a company equals the average cost of capital of its assets, weighted by the amount invested in each asset.

between a relatively large and relatively small contributor to a company's revenue and operating income from year to year. (Staff Ex. 25.0R, pp. 2-3)

Mr. Hevert suggested that it is too restrictive to only include those companies with credit ratings in the BBB range (BBB+ - BBB-) in the credit rating screening used to select the Electric sample. Mr. Hevert is wrong. First of all, it is illogical for Mr. Hevert to argue that Ms. Freetly should have cast a wider net in selecting her electric sample when Ms. Freetly's electric sample comprises more companies than the electric sample he used himself. Second, the formation of a sample requires balancing two goals: (1) creating a sample that is as close in risk to the subject company as possible to minimize measurement error in the sample cost of common equity; and (2) minimizing measurement error inherent in individual company cost of common equity estimates. The first goal is better advanced with a small sample since increasing the size of a sample usually requires adding companies that are farther and farther from the subject company in terms of risk. In contrast, the second goal is better advanced with larger samples since the measurement error inherent in individual company cost of common equity estimates are imperfectly correlated with each other. Consequently, the average measurement error of the sample as a whole declines as the size of the sample increases. In Staff's judgment an Electric sample consisting of 16 companies is large enough to reduce the risk from measurement error inherent in individual cost of common equity estimates while avoiding an increase in measurement error from adding utilities that are less similar to AIC in terms of risk. (*Id.*, p. 4)

ii. Spot Prices versus Average Prices

Ameren witness Hevert claims that average stock prices and bond yields should be used to estimate the investor-required rate of return on common equity. For the DCF analysis, he argues that using a single day spot price fails to account for "aberrant behavior in stock prices, which tend to fluctuate from day-to-day based on changes not only in investors' assessments of fundamental factors, such as earnings growth rates and projected interest rates, but also due to anomalous events that may affect stock prices on any given trading day." (Ameren Ex. 23.0, p. 38) In response, Staff witness Freetly explained that while historical data is useful in examining trends and relationships between variables; direct use of historical data in estimating investor expectations for the future is problematic for several reasons. First, historical data favors information that the market no longer considers relevant over the most recently-available information. Second, historical data reflects conditions that may not continue in the future. Since stock prices reflect all current information, only the most recent stock price can reflect the most recently available information. Historical stock prices must include observations that cannot reflect the most current information available to the market. To the extent investors deem historical data relevant, it is already incorporated into the most recent prices those investors pay for securities. Use of a historical average requires the analyst to subjectively determine what data is no longer relevant, needlessly and inappropriately replacing the collective judgment of all investors with his own. (Staff Ex. 25.0R, pp. 8-9)

Moreover, Mr. Hevert's use of historical data includes the added flaw of inappropriately mixing and matching data from different points in time. The non-constant DCF from his rebuttal testimony, upon which his recommended investor-required rate of return is based, employed average stock prices for the 30-, 90- and

180-day periods ending June 30, 2011. However, the stage one growth rates that he employed in that analysis were concurrent with only the last date used to compute the averages, June 30, 2011.[28] (Tr., September 14, 2011, pp. 403-405) The stock prices from the preceding 30, 90 and 180 days cannot possibly reflect the June 30, 2011 growth expectations Mr. Hevert used in the analysis. The market value of common stock equals the cumulative value of the expected stream of future dividends after each is discounted by the investor-required rate of return. New information becomes available every day and investors rethink their projections of future cash flows, the risk level of the company, and the price of risk. Thus, only a current stock price will reflect all information that is available and relevant to the market. (Staff Ex. 25.0R, p. 9)

Introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Stock prices can be influenced by temporary imbalances in supply and demand; however, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Mr. Hevert already applies. (Staff Ex. 8.0, pp. 34-35)

Further, research has shown that the last observed stock price is the best estimator of future stock prices.[29] The Commission has appropriately adopted costs of capital based on the most recent spot data much more frequently than it has relied on outdated historical data. Indeed, the Commission itself has noted that use of spot data

[28] Mr. Hevert's DCF analysis in direct employed stock prices for the 30-, 90- and 180-day periods ending December 31, 2010, with his stage growth rates measured only on the last date, December 31, 2010. His DCF analyses presented in surrebuttal employed stock prices for the 30-, 90- and 180-day periods ending August 19, 2011, with his stage growth rates measured only on the last date, August 19, 2010.

[29] Malkiel, A Random Walk Down Wall Street, 2007, Norton, p. 132; Foster, Financial Statement Analysis, 1978, Prentice Hall, p. 215.

is a practice the Commission has traditionally relied upon and, in fact, is reluctant to deviate from.[30]

To demonstrate the limited impact of "aberrant" stock prices on the sample cost of common equity estimates, Ms. Freetly updated her analyses several times since filing direct testimony. Tables 1 and 2 below present the results for Ms. Freetly's Gas and Electric samples:

Table 1 – Gas Sample

Date	DCF	CAPM	Average
6-3-11	8.63%	9.31%	8.97%
7-7-11	8.55%	9.37%	8.96%
7-14-11	8.68%	9.43%	9.06%
7-21-11	8.63%	9.46%	9.05%
7-28-11	8.79%	9.44%	9.12%
8-4-11	8.86%	9.21%	9.04%
8-10-11	9.13%	9.14%	9.14%
8-11-11	8.93%	9.26%	9.10%
8-15-11	8.85%	9.23%	9.04%

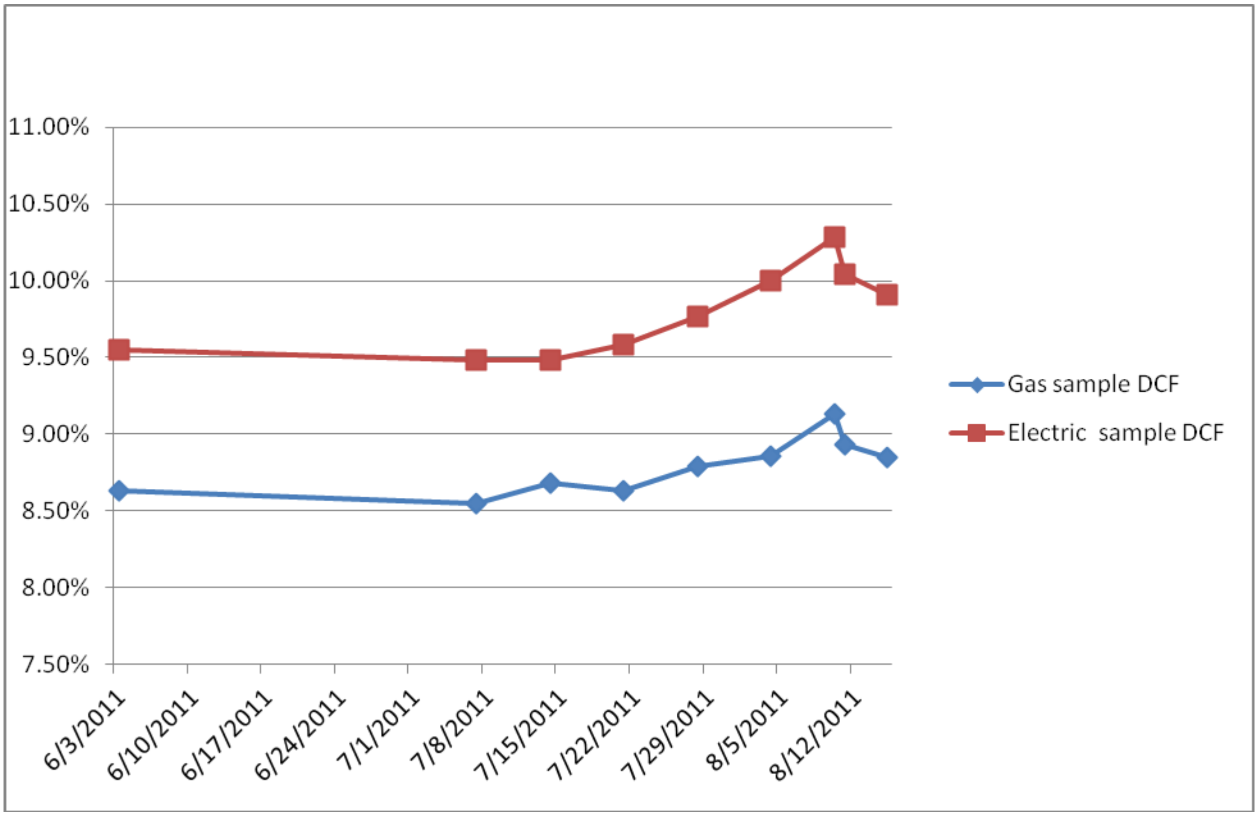
Table 2 – Electric Sample

Date	DCF	CAPM	Average
6-3-11	9.55%	10.32%	9.94%
7-7-11	9.48%	10.36%	9.92%
7-14-11	9.48%	10.36%	9.92%
7-21-11	9.58%	10.48%	10.03%
7-28-11	9.77%	10.46%	10.12%
8-4-11	10.00%	10.30%	10.15%
8-10-11	10.28%	10.26%	10.27%
8-11-11	10.04%	10.34%	10.19%
8-15-11	9.91%	10.32%	10.12%

If spot prices were sensitive to abnormalities, one would expect the DCF estimates to jump around. Instead, as shown in the graph below, the DCF estimates reveal a trend that would be masked by the use of historical averages.

[30] Order, Docket Nos. 07-0241/07-0242 (Cons.), February 5, 2008, p. 92.

Updated DCF Results



Hence, the fact that stock prices changed over the course of two months merely demonstrates that market prices are dynamic and that investors are constantly re-evaluating their expectations. The fact that prices are dynamic highlights the shortcomings of Mr. Hevert's use of historical averages, as the stock prices from up to six months ago that he used obviously do not capture current investor expectations. (Staff Ex. 25.0R, pp. 9-11)

The Commission rejected use of historical stock prices in the Docket No. 03-0403 Order (Aqua, then CIWC, rate proceeding), which stated:

> The Commission is aware that historical data has a place in many cost of capital analyses. The instant objective, however, is to estimate the forward-looking cost of common equity. For this reason, the Commission has consistently rejected the use of

> average common stock prices, and has accepted the use of spot common stock prices when implementing the DCF model. The Commission continues to believe that the use of spot common stock prices in the DCF model is superior to the use of average prices.[31]

In the last rate proceedings for the Company, the Commission rejected AIC's DCF analysis stating that the "over-reliance on historical data is problematic."[32] Consistent with the findings in the previous Ameren rate cases, Mr. Hevert's use of historical data in his cost of common equity analysis should also be rejected in this proceeding.

iii. Growth Rates

The principal difference in the application of the multi-stage DCF is the long-term growth rate. Mr. Hevert incorrectly suggests that the long-term growth rate used in this proceeding should be consistent with the Commission Order in Docket No. 10-0467; however, this approach fails to take into consideration two crucial factors: the expected rate of return on new investment (i.e., earnings) and the rate of earnings reinvestment (i.e., "retention"). The importance of these two factors should be obvious. For example, an economy-wide growth rate, whether 4%, 5%, 6% or even more, is not sustainable on a per share basis if a company does not reinvest a portion of its earnings. That is, the growth rate per share of a company that pays out 100% of its earnings as dividends equals 0% regardless of the magnitude of economy-wide growth. In this case, Mr. Hevert's assumed earnings retention ratios of 33.58% for his electric sample and 30.39% for his gas sample are too low for his electric and gas sample companies to sustain the long-term growth rates he employs. (Staff Ex. 8.0, pp. 37-38)

[31] Order, Docket No. 03-0403, April 13, 2004, p. 42.
[32] Order, Docket Nos. 09-0306 et al. (Cons.), April 29, 2010, p. 216.

Together with the dividend payout rate that Mr. Hevert assumed for 2025 in his updated analysis, the 5.66% growth rate requires an average ROE of 16.86% for his electric sample and 18.63% for his gas sample. In contrast, Value Line projects a rate of return on common equity of 11.69% for his electric sample and 11.95% for his gas sample for the 2013-2015 period. Using the even higher 6.00% long-term growth rate adopted by the Commission in Docket No. 10-0467 would only further exacerbate the unsustainability. In order to sustain 6.00% growth given Mr. Hevert's assumed retention rates (revised in rebuttal), the companies in Mr. Hevert's electric sample would have to indefinitely sustain on average a 17.87% return on retained earnings and the companies in his gas sample would have to indefinitely sustain on average a 19.74% return on retained earnings.

Mr. Hevert suggests that Staff's analysis of the sustainability of growth rates for the sample companies should not be considered because it is premised on the "b times r" approach, which as been rejected by the Commission. (Ameren Ex. 23.0, pp. 33-35) The "b times r" formula provides insight as to what level of growth is sustainable because it can be used to estimate the expected rate of return on new common equity investment for a given growth rate, which is necessary for assessing sustainable growth on a company-specific basis. Thus, Ms. Freetly used the "b times r" formula as a benchmark or guideline to test the sustainability of the growth rates Mr. Hevert employs. As Ms. Freetly is not attempting to estimate the cost of common equity with the "b times r" growth rates in this proceeding, that analysis is not expected to produce implied ROEs precisely in line with the costs of common equity recommended in this proceeding. However, one can expect those implied ROEs to be generally consistent with the cost of common equity recommendations in this proceeding if the growth rates are sustainable. In other words, Ms. Freetly's use of the "b times r" approach serves as a reality check on the level of growth that is plausible. (Staff Ex. 25.0R, pp. 7-8)

Mr. Hevert points out that Ms. Freetly's recommended return for the Company's gas and electric operations is lower than the Value Line projected ROE for the gas and electric samples. (Ameren Ex. 41.0, p. 26) It is important to understand that the expected rate of return on new common equity investment "r" and the investor-required rate of return on their common equity investment are not identical concepts. The former can include both projects that are expected to earn more than the required rate of return and those that are expected to earn less than the required rate of return. (Staff Ex. 25.0R, p. 8)

Mr. Hevert also argued that Blue Chip's forecast 5.70% 30-year U.S. Treasury bond yield for 2021 indicates that Ms. Freetly's 4.8% growth rate is too low. However, this forecasted 30-year U.S. Treasury bond yield overstates long-term economic growth. First, although Treasury yields can be an appropriate proxy for expected nominal GDP growth, the same source provides a direct forecast of nominal GDP growth, hence there is no reason to employ a proxy. The Blue Chip Financial Forecast from which Mr. Hevert obtained the Treasury yield forecast, projected growth of 2.7% for real GDP and 2.2% for inflation as measured by the GDP price index for the 2018-2022 period, which combine into a long-term growth projection for nominal GDP of 4.9%. Second, one would expect Treasury bond yields to be higher than the GDP growth because T-bonds contain a risk premium, which makes U.S. Treasury yields biased forecasts of growth. Therefore, the Blue Chip forecast of 2021 30-year U.S. Treasury bond yields overstates the expected long-term growth rate of the economy.

The 6.00% long-term growth estimate adopted by the Commission in Docket No. 10-0467 was based on historical growth and is not supported by professional forecasters. The investor-required rate of return is a function of investor's expectations of the future, not a mish-mash of historical averages.[33] The EIA projects nominal economic growth of 4.5% for the 2021-2035 period and Global Insight forecasted nominal economic growth of 4.4% for the 2021-2041 period.[34] Staff witness Ms. Freetly used those forecasts of nominal economic growth in calculating her 4.80% long-term growth rate. (Staff Ex. 25.0R, p. 6; Staff Ex. 8.0, p. 9)

In order to make a proper comparison, the following table presents the correct forecasts of growth in nominal GDP beginning in 2021, the final stage of the non-constant DCF analysis.

Table 3: Summary of Long-Term Growth Rates

	Long-Term Growth Rate
Commission Docket No. 10-0467	6.00%
Hevert Revised Long-Term Growth Rate	5.66%
Freetly Long-Term Growth Rate	**4.80%**
Global Insight Nominal GDP Growth	**4.40%**

[33] In Docket No. 10-0467, the company witness derived his 6% long-term growth rate estimate from an average of ten, twenty, thirty, forty, fifty and sixty-year historical averages all ending 2009. The company witness never explained why that average was better than any other average, particularly, given the slow-down in growth over that 60 years (6.9% for the 40, 50, and 60-year averages, 5.8% per year for the 30-year average, 4.9% for the 20 year average and 4.2% for the 10-year average), let alone why that average was better than the forecasts of professional forecasters such as Global Insight and EIA.

[34] The measurement period for long-term economic growth begins in 2021 since this is the start of the long-term growth stage for my multi-stage DCF analysis.

EIA Annual Energy Outlook Nominal GDP Growth	**4.50%**
Blue Chip Financial Forecast Nominal GDP Growth - 2018-2022	**4.90%**

As can be seen in the corrected table above, the professional forecasts support the long-term growth rate that Ms. Freetly used in her analysis and show that the growth rate the Commission accepted in Docket No. 10-0467 and Mr. Hevert's revised long-term growth rates are overstated.

c. CAPM Model Estimates

Risk-free rate

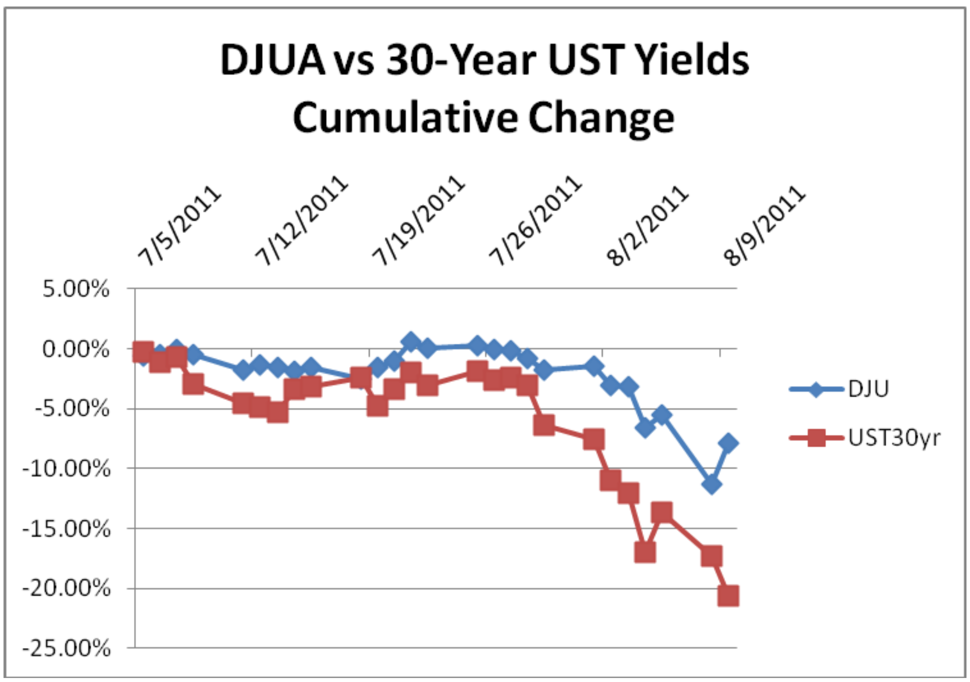
Mr. Hevert wrongly insists that the estimation of the risk-free rate should not be based on spot yields. (Ameren Ex. 23.0, pp. 44-45) Interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic. In contrast, the current U.S. Treasury yields Staff used to estimate the risk free rate reflect all relevant, available information, including investor expectations regarding future interest rates. Consequently, investor appraisals of the value of forecasts are also reflected in current interest rates. Therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. Likewise, if investors believe that the forecasts are not valuable, that belief would be reflected in current market interest rates. In summary, if one uses current market interest rates in a risk premium analysis, speculation of whether investor expectations of future interest rates equals those from a particular forecast reporting service is unnecessary. Further, it is important to note that T-bond yields reflect market forces, while forecasts do not. The true risk-free rate is reflected in the return investors are willing to accept in the market. As of June 3, 2011, investors were willing to accept a 4.26%[35] return on T-bonds, which includes an interest rate risk premium associated with its relatively long term to maturity. That the T-bond yield includes such a premium indicates that the true long-term risk-free rate is actually below 4.26%. (As acknowledged by Mr. Hevert during cross-examination, the 30-year Treasury bond yield had dropped below 4% by mid-September, 2011. (Tr., September 14, 2011, p. 406)) Thus, the Commission should continue to rely on current, observable market interest rates in the risk premium analysis. In the last AIC rate cases, Docket Nos. 09-0306 et.al. (Cons.), the Commission found that the current yield on long-term U.S. Treasury bond is a more appropriate proxy for the long-term risk-free rate than forecasts of that rate.[36]

The Blue Chip forecast of 30-year Treasury bond yields that Mr. Hevert relied on projects that the yield on long-term Treasuries will increase through the third quarter of 2012. If the rise in Treasury yields was indicative of an expected overall increase to the cost of capital, projections for inflation and the growth in the economy would also be rising. However, the same Blue Chip forecast projects that growth in real GDP and inflation are expected to remain relatively flat. Therefore, the projected increase in the yields on Treasury bonds must be due to an expected increase in the interest rate risk premium or a shift in supply and demand (the flow of funds from Treasuries to other investments). An increase in the interest rate risk premium should not be reflected in

[35] Staff Ex. 8.0, p. 16.
[36] Order, Docket Nos. 09-0306 et al. (Cons.), April 29, 2010, p. 214.

the risk-free rate. Further, a flow of funds from Treasuries to common stocks would result in higher stock prices and lower dividend yields.

It is important to note the concurrent decline in Treasury yields with a decline in stock prices. The graph below shows the relationship between the decline in utility stock prices, as depicted by the Dow Jones Utility Average Index and the decline in 30-year U.S. Treasury bond yields from early July to mid-August. This graph illustrates the importance of updating all the components of the cost of equity analysis as of the same date in order to properly reflect the movement in all of the inputs into the calculation. (Staff Ex. 25.0R, pp. 12-14)



Beta

In his direct testimony, Mr. Hevert estimated beta for his sample companies over a twelve month period. For his updated analysis presented in rebuttal, he estimated beta for his sample companies over an eighteen month period. Mr. Hevert claims that a near-term calculation better reflects the current relationship between the proxy group companies and the S&P 500. (Ameren Ex. 3.0G, p. 42, Ameren Ex. 3.0E, p. 40; Ameren Ex. 23.0, pp. 116-117) There is an obvious inconsistency between Mr. Hevert's position on beta estimates and his position against the use of spot stock prices and U.S. Treasury bond yields. On the one hand, he argues that beta must be calculated over a short period to better reflect the current relationship between sample companies' stock prices and the overall market. On the other hand, he argues that stock prices and Treasury bond yields must be estimated using averages that include estimates from up to six months ago, which do not capture current investor expectations.

Beta measured over shorter time periods are more prone to measurement error arising from short-term changes in risk and investor risk preferences, which can bias the beta estimate. A *decrease* in a company's systematic risk could *increase* its estimated beta even though generally an increasing beta would be interpreted as signaling an *increase* in a company's systematic risk. Conversely, an *increase* in a company's systematic risk could *lower* its calculated beta even though generally a decreasing beta would be interpreted as signaling a *decrease* in a company's systematic risk. Those counter-intuitive results are a consequence of the inverse relationship between risk and stock values. As the risk of a stock declines, its price rises, all else equal. In a rising stock market, the beta calculated will rise for a stock that is declining in risk, all else equal. Conversely, in a declining market, the beta calculated will decline for a stock that is increasing in risk. Consequently, a longer measurement period should be used as a more complete business cycle will include both rising and falling markets, reducing measurement error. (Staff Ex. 8.0, p. 39)

Ms Freetly illustrated the inherent volatility when calculating beta using only one year of data with 52-week betas for American Electric Power. The 52 week adjusted beta was 0.80 for 2004, rose to 1.02 for 2005 and then fell to 0.58 for 2006. In comparison, AEP's Value Line beta, which uses 260 weekly observations, was 1.15 at the end of 2004, 1.20 at the end of 2005 and 1.35 at the end of 2006.[37] The wide distribution of the 52-week beta values in three consecutive years demonstrates the inherent volatility in using such a short measurement period to measure beta. (*Id.*, pp. 39-40)

Mr. Hevert disagrees with Staff's beta calculations because they encompass a five-year period and he points out that the beta coefficients are lowest when using the NYSE index and monthly returns. (Ameren Ex. 23.0, p. 47) The betas used by both Mr. Hevert and Ms. Freetly are estimates of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Consequently, which beta estimates are more accurate is unknown. In fact, different beta estimation methodologies can produce different betas when those methodologies employ different samples of stock return data. Thus, just as Mr. Hevert and Ms. Freetly used multiple models to estimate the cost of common equity, Staff used multiple approaches to estimate beta. (Staff Ex. 25.0R, p. 14)

Market Risk Premium

Mr. Hevert developed two estimates of the market risk premium. (Ameren Ex. 3.0G, pp. 38-39) First, he calculated the required return on the S&P 500 Index using the constant growth DCF on all of the companies in the index with long-term growth projections available, including non-dividend paying companies. Nonetheless, the dividend growth rate of non-dividend paying companies cannot be both constant and

[37] Value Line Investment Survey, Summary & Index, December 31, 2004, December 30, 2005 and December 29, 2006.

equal to the earnings growth rate as Mr. Hevert's estimation process assumes. If the dividend growth rate is constant, it must remain 0%. In contrast, the average dividend growth rate of the non-dividend paying companies in Mr. Hevert's analysis equals 15.04%. Mr. Hevert's inclusion of non-dividend paying companies in a constant growth DCF analysis exasperates the upward bias resulting from the unsustainable growth rates used to estimate the market return.

For his second approach to estimate the market risk premium, Mr. Hevert assumed a constant Sharpe ratio, which is the ratio of the risk premium relative to the risk, or standard deviation of a given security or index of securities. Mr. Hevert relied on data from 1926 through 2009 to estimate the historic risk premium and market volatility. Mr. Hevert then estimated the expected market risk premium as the product of the historical risk premium, historical Sharpe ratio and estimates of expected market volatility. The estimate of expected market volatility was calculated using the Chicago Board Options Exchange's ("CBOE") three-month volatility index (i.e., the VXV) and one-month volatility index (i.e., the VIX) for April through June 2011. In addition to the infirmities of historical risk premiums and historical Sharp ratios, Mr. Hevert's reliance on VIX and VXV introduce bias into his estimate of the market risk premium. According to the CBOE, VIX and VXV are not pure measures of expectations; they include a risk premium which varies over time. The CBOE also states that empirical evidence indicates that the risk premium for volatility is negative, which partly explains the <u>continual historical bias of VIX over realized volatility</u>. (Staff Ex. 8.0, pp. 40-41)

Further, as previously discussed, the use of historic data in estimating the forward-looking risk premium is fraught with problems. The magnitude of the historical risk premium depends upon the measurement period used. Unfortunately, no proven method exists for determining the appropriate measurement period. Thus, historical earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation. (*Id.*, pp. 35-36)

Mr. Hevert claims that Staff's ROE recommendations provide investors with an inadequate risk premium because the average equity risk premium for electric and natural gas utilities was higher during 2004-2006 when the Moody's Baa Utility Index yield averaged approximately 6.00%. (Ameren Ex. 23.0, p. 65) Since the equity risk premiums that he presented for the electric and gas utilities are from before the current market crisis, they should not be used to establish the proper equity risk premium to apply in this proceeding. (Staff Ex. 25.0R, p. 17)

The Commission rejected use of historical data in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), a previous rate proceeding of the Company.[38] Referring to Ameren's estimate of the market risk premium, the Commission stated:

> The Commission observes that earned returns on equity are different than expected returns on equity and that the former can not be used to estimate the latter. Additionally, the Commission believes that it would be all too easy to select a historical period that produces a biased result, whether upwardly biased or downwardly biased. As it has done in numerous previous rate cases, the Commission rejects this type of approach to estimating the forward looking cost of common equity. [39]

Once again, in Dockets 09-0306 et.al. (Cons.), the Commission rejected the risk premium analyses of AIC and IIEC because they appeared "to rely too heavily on historical data for the calculation of what should be a forward-looking rate of return on common equity for the market."[40] Consistent with the findings in the previous Ameren

[38] In Docket Nos. 07-0585 – 07-0590 (Cons.), Ameren accepted Staff's cost of common equity recommendation in its Initial Brief. Hence the Commission did not address Ms. McShane's analysis in the Final Order. (Order, Docket Nos. 07-0585 – 07-0590 (Cons.), Sept. 24, 2008, p. 180)

[39] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, pp.142-143.

[40] Order, Docket Nos. 09-0306 et al. (Cons.), April 29, 2010, p. 214.

rate cases, Mr. Hevert's use of historical data in his cost of common equity analysis should also be rejected in this proceeding.

d. Other ROE Estimation Models

e. Proposed Adjustments to Cost of Equity

i. Uncollectibles Rider Adjusment

Ms. Freetly recommends that her cost of common equity estimates be adjusted downward to reflect the reduction in risk associated with the use of the uncollectibles riders authorized by the Commission. These cost recovery mechanisms ensure more timely and certain collection of bad debt expense, thereby providing greater assurance that the Company will earn its authorized rates of return. Therefore, it is appropriate for the Commission to reduce the rate of return on common equity to recognize the reduction in risk associated with the use of the uncollectibles riders. (Staff Ex. 8.0, p. 31)

Ms. Freetly's proposed adjustment for Riders GUA and EUA reflects the approach accepted by the Commission in the last AIC rate cases. She estimated the effect Riders GUA and EUA would have on the Company's Moody's credit ratings and based her adjustments on the resulting change in the implied yield spreads. Of the four rating factors Moody's focuses on in its analysis of electric utilities, the adoption of an uncollectibles rider would most affect the cost recovery factor, which assesses a firm's ability to fully recover prudently incurred costs in a timely manner. Thus, a rider designed to reduce uncertainty in cash flows would positively affect the cost recovery factor. Moody's assigns a weight of 25% to the cost recovery factor in determining the overall credit rating score. Ms. Freetly assumed that the credit rating assigned to this factor would improve by one credit rating (i.e., 3 points on the numeric scale) with the uncollectible riders. Since this factor composes 25% of the overall weighting, raising the score for this factor by one credit rating suggests that AIC's return on common equity should be reduced by 25% of the spread between AIC's current rating and the next higher credit rating. The June 14, 2011 spread between the Company's Baa3 rating and the A3 was 65 basis points. Thus, Ms. Freetly concluded that AIC's return on common equity should be reduced by 16.25 basis points (25% * 65 = 16.25) to reflect the reduction in operating risk stemming from Riders GUA and EUA. (Staff Ex. 8.0, pp. 30-33)

Mr. Hevert presented an analysis of the yields to maturity for senior, unsecured utility bonds and claimed that the wide variation in yields demonstrates the imprecision inherent in Staff's approach to adjust for the reduction in risk due to the uncollectible riders. (Ameren Ex. 23.0, pp. 60-61) Mr. Hevert's analysis is irrelevant. The 65 basis point spread that is the basis of Ms. Freetly's adjustment for the uncollectible riders is drawn from Reuters Corporate Spreads for utility bonds, which represent the basis point spread over U.S. Treasury for an index of securities with the same maturity that were issued at the same time. Mr. Hevert's analysis relied on individual bond yields that are not directly comparable rather than an index of securities. His exhibit also shows that several bond issues had not traded in weeks, demonstrating that yields on those specific bond issues are out of date and that individual bonds are illiquid. The Reuters spreads more clearly illustrate the price of the risk level attributed to different credit ratings and serves as a proxy for the risk reduction as a result of the Company being more assured of earning its authorized rate of return. (Staff Ex. 25.0R, p. 15)

Hevert Event Studies

Mr. Hevert performed an event study to assess investors' reactions to the implementation of uncollectible riders, claiming that to the extent investors believe that risk will be significantly lower for companies that implement revenue stabilization mechanisms, the stock returns of companies that implement such mechanisms should be less volatile with the decoupling mechanism in place. For his event study, he analyzed the relationship between the stock returns of a company that implemented uncollectible riders and an index of gas utility returns prior to the implementation of uncollectible riders and after the implementation of uncollectible riders. He concluded that there was no meaningful change in the relationship between the implementing company's stock returns and the market index as a result of the implementation of the uncollectible riders. He then concluded there was no empirical basis to conclude that the implementation of uncollectible riders would meaningfully reduce investors' return requirements. (Ameren Ex. 3.0G, p. 66)

Mr. Hevert's empirical analyses should not be considered in determining whether an adjustment is necessary to reflect the decreased risk from the implementation of the uncollectible riders for four reasons: First, they do not examine the effect of a single event on stock price, but rather they compare the cumulative effect of all events during his observation period. The uncollectible riders for Detroit Edison and Michigan Consolidated Gas ("MichCon") came within rate cases in which the Michigan Public Service Commission authorized a rate increase for the Companies. (Tr., September 14, 2011, p. 411) Consequently, his analyses do not isolate the effect of a single rate design change from the broader effect of the entire rate order, let alone other company-specific changes that might have occurred during the analysis period. In fact, Mr. Hevert admitted during cross examination that it is really difficult to separate the effects of individual rider adjustments. Further, he admitted that he did not investigate the reasons for large changes in DTE's stock price during the post-event period, such as the 3.75% increase in DTE's stock price on October 19, 2009 or earnings guidance announcements made by DTE Energy during his event period, stating "It was certainly not something that was important to my analysis." (Tr., September 14, 2011, pp. 413-415; Staff Group Cross Ex. 11-G)

Second, he set the "event date," arbitrarily. Ms. Freetly testified that if the "event date" is too early, then pre-rate decision factors will dilute the effect of the rate order on risk. If the "event date" is too late, then the effect of the rate order on risk will be absorbed into the pre-rate decision period. (Staff Ex. 8.0, p. 45) According to an article Mr. Hevert alleges supports his event study methodology, "event period uncertainty causes event studies of regulatory changes to have low power in detecting any impact." Low power tests will cause the analyst to conclude that a change in regulation did not have any impact despite the fact that it did.[41] (Staff Group Cross Exhibit 11-D)

Further, the same article Mr. Hevert alleges supports his event study methodology actually cautions against the use of one event study of a regulatory change as the representation of its true impact. To confirm his results, Mr. Hevert could have looked at other variables that would be affected by the implementation of the uncollectible riders, such as the impact on the operating income of the companies. This

[41] Company response to Staff Data Request JF-7.03, Attach 3, pp. 179-180.

article concludes that event studies of regulatory changes are difficult to conduct in a way that is unassailable. (Staff Group Cross Exhibit 11-D)

Mr. Hevert's event studies rely on the stock returns of DTE Energy, the parent company of Detroit Edison and MichCon, which creates another infirmity. Despite Mr. Hevert's claim that DTE's total operating income is highly concentrated in the Detroit Edison operating subsidiary, his own workpapers show that Detroit Edison's net income was only 49.33% of DTE total net operating income. (Ameren Ex. 3.0E, p. 60) MichCon's net income was only 15.79% of DTE total net operating income. (Staff Group Cross Exhibits 11-E and 11-F) Obviously, the combination of non-utility earnings and the non-concurrent adoption of uncollectibles riders for gas and electric service will dilute the effect of either rider on DTE Energy's stock returns.

ii. Financial Risk Adjustment

To estimate the financial risk adjustment to the Gas and Electric samples, Ms. Freetly compared the values for the 3-year average financial guideline ratios computed from 2008 through 2010 for each of the companies in the Gas and Electric samples and AIC to Moody's guidelines for regulated gas and electric utilities. To assess the financial strength of gas and electric utilities, Moody's focuses on four ratios: (1) funds from operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow ("RCF") to total debt coverage; and (4) debt to capitalization.

As shown below in Table 4, AIC's 3-year average ratios are consistent with a Baa1 credit rating, the Gas sample's 3-year average ratios are consistent with an A3 credit rating, and the Electric sample's 3-year average ratios are consistent with a Baa2 credit rating.

Table 4 – Moody's Guideline Ratios for Regulated Electric and Gas Utilities

	Aaa	Aa	A	Baa	Ba
Financial Guideline Ratios					
FFO/IC	> 8.0x	6.0-8.0x	4.5-6.0x	2.7-4.5x	1.5-2.7x
FFO/Debt	> 40%	30-40%	22-30%	13-22%	5-13%
RCF/Debt	> 35%	25-35%	17-25%	9-17%	0-9%
Debt/Capitalization	< 25%	25-35%	35-45%	45-55%	55-65%
AIC					
FFOIC				4.0x	
FFO/Debt				21.5%	
RCF/Debt				16.4%	
Debt/Capitalization				46.0%	
Gas Sample					
FFOIC			5.9x		
FFO/Debt			25.4%		
RCF/Debt			18.8%		
Debt/Capitalization				51.3%	
Electric Sample					
FFOIC				4.4x	
FFO/Debt				21.4%	
RCF/Debt				16.6%	
Debt/Capitalization					56.1%

Financial theory 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. In comparison to AIC's Baa1 level of financial strength, the Gas sample's A3 level of financial strength indicates less financial risk than AIC. Thus, the Gas sample's average cost of common equity needs to be adjusted upward to determine the final estimate of the AIC Gas' cost of common equity.

In contrast, the Electric sample's Baa2 level of financial strength indicates that it has more financial risk than AIC. Thus, the Electric sample's average cost of common equity needs to be adjusted downward to determine the final estimate of the AIC Electric's cost of common equity. (Staff Ex. 8.0, pp. 27-28)

Using 30-year utility debt yield spreads published by Reuters, Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for AIC and those of the Gas and Electric samples. The spread between the implied ratings of Baa1 for AIC and the A3 for the Gas sample is 30 basis points. The spread between the implied ratings of Baa1 for AIC and Baa3 for the Electric sample is 20 basis points. To determine the cost of common equity adjustments, Ms. Freetly multiplied the yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios. Thus, Ms. Freetly's financial risk adjustment to the cost of common equity is an increase of 9 basis points for AIC's natural gas distribution operations to reflect the higher financial risk of AIC in comparison to the Gas sample; whereas, her financial risk adjustment to the cost of common equity is a decrease of 6 basis points for AIC's electric delivery service operations to reflect the lower financial risk of AIC in comparison to the Electric sample. (Id., pp. 29-30)

Mr. Hevert claimed that Ms. Freetly failed to consider company-specific business risk in comparing the risk of the Company to that of her Gas and Electric samples. (Ameren Ex. 23.0, p. 66) He specifically mentions two-company specific risks that Ms. Freetly allegedly failed to consider: (1) the weather-related risk for the Company's natural gas operations due to the lack of a weather normalization clause; and (2) the higher level of regulatory risk for utilities in the State of Illinois. First of all, the same credit ratings range that Ms. Freetly used to establish comparability (and which Mr. Hevert criticized as being "too restrictive") reflects both of those risks. In addition, Ms. Freetly compared the Standard & Poor's business profile scores for AIC and the Gas and Electric samples. S&P states that AIC's "excellent" business risk profile reflects its lower-risk pure transmission and distribution operations and is also affected by its ability to manage its regulatory risk. The average business risk profile of both Staff's Gas and Electric samples is also "excellent." Hence, Staff's samples are comparable to AIC in terms of business risk. Further, with regard to the lack of weather normalization, AIC is allowed to recover 80% of fixed costs through rates. This high level of fixed cost recovery mitigates the need for weather normalization as it largely decouples rates from usage. (Staff Ex. 25.0R, pp. 17-18)

iii. Flotation Cost Adjustment

The flotation cost adjustment proposed by Mr. Hevert is inappropriate. The Commission Order from Docket No. 94-0065 states that "The Commission has traditionally approved [flotation cost] adjustments only when the utility anticipates it will issue stock in the test year or when it has been demonstrated that costs incurred prior to the test year have not been recovered previously through rates."[42] Moreover, that Order states that "[the utility] has the burden of proof on this issue." Thus, flotation costs are to be allowed only if a utility can verify both that it has incurred the specific amount of flotation costs for which it seeks compensation and that those costs have not been previously recovered through rates. The Company has done neither.

Mr. Hevert's flotation cost calculations were based on the costs of issuing equity that were incurred by Ameren Corp. and his sample group companies in their two most recent common equity issuances.[43] Based on those issuance costs, he calculated a flotation cost of 0.14% for the electric delivery service operations and 0.13% for the

[42] Order, Docket No. 94-0065, pp. 93-94.
[43] Ameren Exhibit 3.0E, p. 54 and Ameren Exhibit 3.0G, p. 60.

natural gas distribution operations. He did not make a specific flotation cost adjustment, but claims to have considered the effect of flotation costs in determining where AIC's ROE falls within the range of results.

The Commission has repeatedly rejected generalized flotation cost adjustments in previous cases as an inappropriate basis for raising utility rates.[44] Since Mr. Hevert's calculation is not based on issuance costs that the Company has incurred but has not previously been recovered through rates, it should not be considered in setting the investor required rate of return on common equity.

D. Recommended Overall Rate of Return

1. Electric

Staff recommends an 8.650% rate of return on rate base for the Company's electric delivery services. (Staff Ex. 24.0, Sch. 24.01)

AIC Electric Delivery Services
Average 2012 Cost of Capital Summary

Capital Component	Balance	Weight	Cost	Weighted Cost
Preferred Stock	$59,158,692	1.720%	4.98%	0.086%
Short-Term Debt	6,473,198	0.188%	2.24%	0.004%
Long-Term Debt	1,591,564,788	46.276%	7.44%	3.443%
Common Equity	1,782,091,061	51.816%	9.72%	5.037%
Bank Commitment Fees				0.080%
Total	$3,439,287,739	100.000%		8.650%

2. Gas

[44] Order, Docket No. 01-0696, September 11, 2002, pp. 23-24; Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, pp. 83 and 89; Order, Docket Nos. 01-0465/01-0530/01-0637 (Cons.), March 28, 2002, pp. 75 and 79; Order, Docket No. 04-0779, p.94; Order, Docket Nos. 07-0241/07-0242, February 5, 2008, p. 102.

Staff recommends an 8.225% rate of return on rate base for the Company's gas delivery services. (Staff Ex. 24.0, Sch. 24.01)

AIC Gas Delivery Services
Average 2012 Cost of Capital Summary

Capital Component	Balance	Weight	Cost	Weighted Cost
Preferred Stock	$59,158,692	1.720%	4.98%	0.086%
Short-Term Debt	6,473,198	0.188%	2.24%	0.004%
Long-Term Debt	1,591,564,788	46.276%	7.44%	3.443%
Common Equity	1,782,091,061	51.816%	8.90%	4.612%
Bank Commitment Fees				0.080%
Total	$3,439,287,739	100.000%		8.225%

V. COST OF SERVICE

A. Overview

Ameren's actions in the filing of its ECOSS for the entire Illinois service territory have undermined the review and analysis of the Company's proposed rates, leaving Staff and other parties with a deficient foundation on which to address ratemaking issues in this case. Under these difficult circumstances, Staff's proposed revenue allocations and rate design provide the most reasonable ratemaking approach and should be adopted in this case.

B. Resolved Issues

1. Electric

a. Substation Costs Allocated to DS-4 100+ kV Customers

b. Supply vs. Service Voltage Allocations

2. Gas

a. Allocation of Rider TBS Costs to Customer Classes

The Company proposed an unbundled, subscribable transportation banking service presented in Ameren Illinois' tariff as Rider Transportation Balancing Service ("Rider TBS"). (Ameren Ex. 14.0G, p. 7) The Company has determined the effect on various base rates which will occur once Rider TBS becomes operational. Specifically, transportation banking services costs were removed from transportation-related base rates in Rates GDS-2, GDS-3, GDS-4, and GDS-5. This removal of costs from the calculation of transportation base rates will result in lower proposed base rates. For example, the Rider TBS associated costs allocated to GDS-5 will result in a lower Delivery Charge for customers taking this service. (Ameren Ex. 13.0G, p. 18)

For Rider TBS to be approved, Staff believes that it should not only make sense from a policy perspective, but that the Company must demonstrate that the rates charged under the rider are reasonable, i.e., cost based. If the proposed rider satisfies the policy criteria but does not meet the cost standard, then it should not be approved. (Staff Ex. 15.0, p. 39)

In direct testimony, Mr. Rukosuev demonstrated that neither the Company's Initial gas ECOSS nor the deficiency gas Rate Zone ECOSSs provided an accurate measure of the cost of service. Therefore, Staff recommended that since the proposed Rider TBS does not meet the cost standard, its implementation should be delayed until the Company files a valid, supportable cost of service study, which would presumably occur in Ameren's next rate case. (Staff Ex. 15.0, pp. 39)

In rebuttal testimony, the Company provided revised Rate Zone ECOSSs. Staff reviewed these ECOSSs and found them to be an improvement from the ECOSS provided in the Company's initial filing and the gas Rate Zone ECOSSs provided in response to the ALJs' deficiency letter. Subsequently, Mr. Rukosuev revised his position with respect to implementation of Rider TBS and recommended that it be approved for the following reasons:

a. Mr. Rukosuev's primary concerns with the deficiency gas Rate Zone ECOSSs have been addressed by Ameren. (Staff Ex. 31.0, pp. 4-8)

b. The allocation of costs to the customer classes are based upon various allocation methodologies, which Mr. Rukosuev accepted. (*Id.*, p. 7)

c. Rider TBS should be approved given the Company's customers' desire for alternative banking services as discussed by ICC Staff witness Mr. David Sackett. (Staff Ex. 29.0, pp. 9-33)

C. Contested Issues

1. Electric/Gas

a. Use of Embedded Class Cost of Service Studies (ECOSS)

Ameren presented a single electric and a single gas ECOSS for the entire Illinois service territory ("Initial electric ECOSS" and "Initial gas ECOSS" or collectively referred to as "Initial ECOSSs") as part of its initial filing in this docket. Ameren witnesses

Schonhoff (electric) and Althoff (gas) sponsored and supported their respective ECOSSs. (Am. Ex. 14.1E, p. 2 and Am. Ex. 13.0G, pp. 4-10) The filing of a single ECOSS[45] for the entire Illinois service territory constitutes a change from Ameren's previous rate case (Docket Nos. 09-0306-09-0311 (Cons.)) where Ameren separately filed for its electric and gas operations three separate ECOSSs for AmerenCIPS, AmerenCILCO and AmerenIP, respectively. (Docket Nos. 09-0306-09-0311 (Cons.) Schedule E-6) (Staff Ex. 14.0, p. 4 and Staff Ex. 15.0, pp. 8-9) To justify the filing of a single ECOSS, Company witness Jones notes[46] "that the former legacy utilities have been reorganized and merged into one utility" and that the Company has received approval to implement a single tariff book. (Ameren Ex. 13.0E, p. 6) However, the single tariff book that was filed contains distinct tariffs for each of the former Ameren Illinois utilities. Mr. Jones did not explain why filing the tariffs for the legacy utilities in a single tariff book gave Ameren the authority to include only one electric ECOSS in its initial filing. (Staff Ex. 14.0, p. 5) Similarly, with respect to Mr. Rukosuev's concerns that AIC did not directly explain its decision to file only the Initial gas ECOSS, Company witness Althoff stated in her rebuttal testimony that "AIC's Initial ECOSS was presented in accordance with AIC's interpretation of the Part 285 rules. (Ameren Ex. 33.0, p. 5)

The initial filing was made before the Commission issued its decision in Docket No. 10-0517, which addressed the issue of whether Ameren should use one or three Rate Zone ECOSSs for ratemaking. Despite having acknowledged the Commission's

[45] Mr. Schonhoff sponsored AIC's electric embedded cost of service study performed for the electric retail jurisdictional delivery services. Ms. Althoff sponsored AIC's gas embedded cost of service study performed for the gas retail jurisdictional delivery services.
[46] With respect to the Initial gas ECOSS, Company witness Althoff made a similar statement. (*see* Ameren Ex. 13.0G, p. 11)

authority on this matter, the Company chose to act unilaterally and sponsor a single ECOSS in its initial filing. This reflects a knowing disregard of the regulatory process.

Testimony by Company witness Jones buttresses this conclusion. He acknowledged that Ameren was well aware that, at the time of its initial filing, the Commission had yet to decide between using one or three ECOSSs for ratemaking in Docket No. 10-0517. (Tr., September 15, 2011, p. 763) Mr. Jones stated that he was not aware of any concern expressed within the Company before the initial filing that the filing might not be consistent with the Commission Order in Docket No. 10-0517. (*Id.*, p. 756) He noted that the Company did not consider providing three rate zone ECOSSs in its initial filing to address the possibility that the Commission would rule against Ameren on the ECOSS issue in Docket No. 10-0517. (*Id.*,) Furthermore, he stated that at the time of the initial filing, Ameren was aware that the Administrative Law Judge's ("ALJ") Proposed Order in Docket No. 10-0517 issued on January 31, 2011 recommended that ratemaking be based on three Rate Zone ECOSSs rather than one. (*Id.*, pp. 756-757) Mr. Jones was not aware of any discussion within the Company to revise or postpone its initial filing because of the ECOSS ruling in the ALJ Proposed Order. Nor did Ameren make any changes to its planned initial filing as a result of the ALJ Proposed Order. (*Id.*, pp. 761-762) Finally, despite the Proposed Order, Ameren performed no work on preparing three rate zone ECOSSs before the final Commission Order in Docket No. 10-0517 that was issued on March 15, 2011. (*Id.*, p. 758)

Mr. Jones claimed in his rebuttal testimony that "at no point did AIC attempt to take preemptive measures that limit the Commission's range of action." (Ameren Ex. 13.0, p. 15) When asked directly whether he considered filing a single ECOSS before the Commission decided between one and three ECOSSs in Docket No. 10-0517 to be a preemptive measure, Mr. Jones insisted it was not. (*Id.*, p. 762) The available evidence says otherwise. Filing a single ECOSS was a preemptive measure with adverse consequences for the parties and the regulatory process.

Subsequent events required Ameren to separately submit for its electric and gas operations three Rate Zone ECOSSs. On February 23, 2011, the ALJs in this docket issued a deficiency letter ("February Deficiency Letter") stating that a single ECOSS does not meet the requirements of Section 285.5110 of the Illinois Administrative Code (83 Ill. Adm. Code) and directed Ameren to provide a separate ECOSS for each rate zone. (Staff Ex. 14.0, p. 5) On March 15, 2011, the Commission issued its Final Order in Docket No. 10-0517, which rejected the single ECOSS in favor of three Rate Zone ECOSSs for the electric and gas operations. The Commission stated, "[a]s long as separate rates are charged for each of the three legacy utilities, the costs and revenues of each legacy utility should be considered when rates are set. (*Id.*, p. 21) (Staff Ex. 14.0, p. 6) The Commission further criticized Ameren's use of a single electric and gas ECOSSs for ratemaking, stating that,

> "[b]y combining the data and information of the legacy utilities as suggested in Proposal 5, by its own admission AIC gives no consideration to the historic costs which are the foundations of current rates. As the Commission and the parties well know, AmerenIP has historically had the highest rates of the three legacy utilities while AmerenCILCO has had the lowest rates. Combining all class rates across zones overnight (literally as AIC suggests) would unfairly benefit customers of the former AmerenIP and unfairly harm customers of the former AmerenCIPS and AmerenCILCO." (Final Order, Docket No. 10-0517, March 15, 2011, p. 20)

On March 24, 2011, Ameren responded to the ALJs' February deficiency letter by filing the three electric and gas Rate Zone ECOSSs ("Rate Zone ECOSSs"), one for each of the former Ameren Illinois utilities that were merged. (Response of AIC to List of ALJ's Deficiencies dated February 23, 2011) (Staff Ex. 14.0, p. 6 and Staff Ex. 15.0, p. 8)

That reply presented a number of problems for Staff and the other parties. First, the three deficiency Rate Zone ECOSSs were tardy, coming more than a month after the initial filing, thereby delaying the parties' review and analysis. Second, the deficiency Rate Zone ECOSSs were significantly flawed. Third, the deficiency Rate Zone ECOSSs were not accompanied by testimony or explanation of how they were prepared which further inhibited the parties' review. (Staff Ex. 30.0, p.5, Staff Ex. 31, p.6, and Tr., September 15, 2011, p. 767-768)

Fourth, the reply contained no rate design changes (Tr., September 15, 2011, p. 762) which means that the Company continued to base rates on a single ECOSS despite the Commission's directive in Docket No. 10-0517 that these be based on the three separate rate zones. (Staff Ex. 14.0, pp. 10-14)

The shortcomings in the deficiency Rate Zone ECOSSs were extensively explored in the direct testimonies of Staff witnesses Lazare (electric) and Rukosuev (gas). They identified various problems with the balances for both plant and reserve for depreciation accounts. (Staff Ex. 14.0, pp. 9-15 and Staff Ex. 15.0, pp. 12-17)

The problems lie not in the overall general functional categories of costs such as Intangible Plant, Transmission Plant, Distribution Plant and General Plant, but rather at individual FERC account levels. (Staff Ex. 14.0, p. 10 and Staff Ex. 15.0, p. 10) One problem concerns the accuracy of the costs presented at the FERC account level which were determined in a different way than in previous ECOSSs for the three legacy utilities. The deficiency Rate Zone ECOSSs used the expedient approach of basing rate zone FERC account balances on allocations reflecting their respective shares of the general plant category containing that FERC account. For example[47], since Rate Zone III (AmerenIP) accounts for 51.0% of Ameren's September 2010 Illinois distribution plant, each of its distribution-related FERC accounts were allocated 51.0% of the Illinois costs pertaining to that account. (Ameren response to Staff DR PL 12.01) (Staff Ex. 14.0, p. 10) This approach raises a concern because Ameren offered no support for its assumption that a rate zone's FERC account balance is proportional to its share of the general plant category containing that account. In fact, evidence from Ameren's previous rate case, Docket Nos. 09-0306-09-0311 (Cons.), suggests that individual accounts will diverge from the functional totals. (See for example, Staff Ex. 14.0, Schedule 14.02 and Staff Ex. 15.0, Schedule 15.03) Thus, there is no reason for Ameren to assume that the ratios of FERC account balances between the three rate zones will be the same. (Staff Ex. 14.0, pp. 11-12 and Staff Ex. 15.0, pp. 14-15)

These discrepancies undermine the value of the deficiency Rate Zone ECOSS results. Different distribution plant and reserve accounts require different allocators to be cost based. Account 364-Pole, Towers and Fixtures is allocated on the basis of a demand allocator while Account 370-Meters is allocated on a customer basis. Understating the reserve for depreciation for Poles, Towers and Fixtures and overstating for Meters could benefit smaller customers who generally receive a greater allocation of customer costs than demand costs. When the opposite is true, large

[47] For each gas FERC account, Ameren begins with the total amount for its Illinois jurisdiction. That Illinois total is then allocated to the three rate zones generally based upon their respective shares of the category of plant which contains that FERC account. In direct testimony, Mr. Rukosuev prepared an illustration of the approach, presented in the attached Schedule 15.01. For example, Rate Zone I (AmerenCIPS), Rate Zone II (AmerenCILCO), and Rate Zone III (AmerenIP) accounts for approximately 21.0%, 29.0% and 50.0% of Ameren's September 2010 Illinois distribution plant, respectively. Then, the Company's proposed approach allocates these percentages of each FERC account for the Illinois jurisdiction to Rate Zone I, II and II, respectively. (Staff Ex, 15.0, p.13)

customers benefit. Either situation produces inaccurate results. (Staff Ex. 14.0, p. 12 and Staff Ex. 15.0, pp. 14-15)

The subfunction balances for Account 364-Poles, Towers and Fixtures and Account 365-Overhead Conduit and Devices are inaccurate as well, which presents a problem because the Subtransmission, Primary and Secondary subfunctions are each allocated differently to customer classes. (Staff Ex. 14.0, p. 13 and Staff Ex. 15.0, pp. 14-15)

Aside from the concerns presented above, which focus on how functional categories are broken down into individual FERC accounts, Staff also expressed concerns because the sum of the FERC accounts for the three rate zones did not always equate to the total for those accounts in the Illinois-wide electric and gas ECOSSs' presented in the Initial Filing. (Staff Ex. 14.0, p. 10 and Staff Ex. 15.0, p. 12) Staff presented an illustration of the differences in individual FERC accounts between Rate Zone and Illinois-Wide ECOSSs reserve for depreciation. (Staff Ex. 14.0, Schedule 14.03 and Staff Ex. 15.0, Schedule 15.04)

These problems with Ameren's deficiency Rate Zone ECOSSs also affect those expenses that are allocated according to plant totals. For example, Accounts 581-Load Dispatching, 598-Miscellaneous Distribution Plant, 924-Property Insurance and 927-Franchise Requirements, as well as depreciation and amortization of the regulatory asset and franchise taxes, are allocated according to distribution plant. Any inaccuracies in distribution plant balances at either the FERC account or subfunction level distorts the resulting allocations of these expense accounts. (Staff Ex. 14.0, p. 14)

Taken together, these shortcomings affect the degree to which the deficiency Rate Zone ECOSSs can be used in the ratemaking process. The problems at the

FERC account level mean they cannot be used to allocate revenues or design rates at the customer class level. However, the studies can still play a limited role in guiding the allocation of total system costs to the three Rate Zones. As noted, the problems with the studies lie not at the general functional level but rather with the individual FERC accounts. Those general functional level costs may still be used to determine how each of the rate zones recover costs on an overall basis under current and proposed rates. For example Rate Zones I, II and III currently earn rates of returns of 5.76%, 4.61% and 9.05% respectively. The higher return for Rate Zone III indicates it should receive a smaller increase than Zones I and II. Since Rate Zone III has higher current rates, the results provide support for moving closer to uniform rate levels as Ameren proposes. (Staff Ex. 14.0, pp. 14-15 and Staff Ex. 15.0, pp. 16-17)

The Company did not object to Staff's's criticisms and, in fact, acknowledged[48] that they were reasonable. (Tr., September 15, 2011, p. 773-774) Furthermore, Company witness Schonhoff indicated that the Company revised its Rate Zone ECOSSs in its rebuttal testimony to address Mr. Lazare's concerns, focusing in particular on the FERC account balances that Mr. Lazare found problematic. Mr. Schonhoff concluded concerning these revised studies:

> As indicated by Mr. Lazare, the cost of service allocation methods used in the Rate Zone ECOSS are the same as those used in the prior proceeding as accepted by the Commission. Mr. Lazare specifically identifies one allocator used for allocating substations and primary lines, and agrees the Company's method is also appropriate given the Commission's recent order. For these reasons, I see no reason why the updated ECOSS models couldn't be used to support rate design proposals by Ameren Illinois, Staff and other Interveners. (Ameren Ex. 32.0, p. 9)

[48]For Gas, Ms. Althoff appears to agree with Mr. Rukosuev's criticism as well. (Ameren Ex. 33.0, p. 3)

While Staff considers the revised Rate Zone ECOSSs provided in rebuttal testimony to be an improvement upon the Company's previous efforts in this case, they nevertheless remain problematic. The problem lies with the length of time Ameren took to address the shortcomings in its previous ECOSS approaches which severely impaired the review by Staff and other parties. As discussed above, when the Company filed its rate case on February 18, 2011, it ignored the likelihood that the Commission would require separate ECOSSs be prepared for the three rate zones. It was only on March 24, nine days after the March 15, 2011 Final Commission Order requiring separate Rate Zone ECOSSs, that Ameren filed the required Rate Zone ECOSSs in response to the ALJs' deficiency letter. However, even when it filed the three Rate Zone ECOSSs, it failed to present any testimony explaining how those ECOSSs were developed. It was only when the Company filed its rebuttal testimony, more than five months after the initial filing, that Ameren witness Jones presented a revised set of cost and ratemaking proposals based upon the revised cost studies for each of the three rate zones. This sequence of events left Staff and other parties with only rebuttal testimony, hearings and briefs in which to discuss and debate Ameren's revised ratemaking proposals. This truncated schedule inhibited a complete and thorough discussion of the rate design issues in this case. (Staff Ex. 30.0, pp. 4-5)

Based on the forgoing, Staff submits that the revised Rate Zone ECOSSs presented in the Company's rebuttal testimony could not be verified as reasonable for ratemaking purposes in this case. The significant delay in producing the revised Rate Zone ECOSSs made it difficult to determine whether these studies do, in fact, provide a reasonable foundation for ratemaking in this case. Due to the delay, these complex studies had to be reviewed and analyzed within a severely truncated timeframe. Each

ECOSS contains hundreds of cost accounts that are allocated by a variety of allocators based on data developed for each rate zone. A thorough review of the accuracy of each study requires considerably more time than that provided in the rebuttal stage of a rate case, which was all the time allowed by Ameren's untimely provision of its revised Rate Zone ECOSS. (Staff Ex. 30.0, pp. 5-6)

2. Electric

a. Allocation of Public Utilities Revenue Act (PURA)/Electric Distribution Tax Expense

The evidence in this case supports the allocation of distribution taxes on a volumetric per-kWh basis. The IIEC-proposed alternative based largely on plant has previously been rejected by the Commission and should be rejected in this case as well.

IIEC witness Stephens presents a number of arguments in favor of a distribution tax allocator primarily based on plant. (IIEC Ex. 1.0, p. 30) He contends that the level of PURA taxes for individual utilities is mostly based on pre-1998 invested tax levels rather than usage and that the current tiered per-kWh rates are designed to mimic the previous plant-based allocation approach. (*Id.*, pp. 21-22)

This argument is not convincing. It is true that: (1) the distribution tax was previously determined by the levels of investment plant, and (2) the initial levels of the taxes paid by individual utilities were based on previously calculated amounts determined by their respective plant investment levels. However, the Illinois General Assembly changed the way the distribution tax is determined in its Amendatory Act of 1997 from a tax on "invested capital" to a "tax based on the quantity of electricity that is delivered." (35 ILCS 620/1a, P.A. 90-561, eff. 1-1-98)

While the starting point for the tax levels after the Amendatory Act of 1997 corresponds to previous tax levels based on invested capital, usage has since become the determining factor for these taxes. Furthermore, the total amount of distribution taxes collected by utilities increases each year by the lesser of 5% over the existing level or the yearly consumer price increase. Neither of these factors bears any relationship to plant investments. (Staff Ex. 30.0, p. 19)

Mr. Stephens questions the role of usage in determining PURA taxes. He contends that a utility's PURA tax burden can increase or decrease even if its kWh deliveries do not change because that burden depends on the utility's deliveries relative to other utilities. (IIEC Ex. 1.0, pp. 25-26) This argument is confusing as it acknowledges the role played by deliveries in the calculation, but seeks to make a distinction because the driver is the utility's share of deliveries, rather than their absolute levels. Either way, the focus is on deliveries, rather than invested capital, which IIEC proposes to use for these costs. (Staff Ex. 30.0, p. 19)

Mr. Stephens also presents an analysis designed to show that Ameren's historical tax burden has not been highly correlated with its kWh deliveries. Based on this analysis, he considers it unreasonable to allocate the PURA tax entirely on kWh deliveries. . (IIEC Ex. 1.0, pp. 25-26) The analysis is not convincing. The fact remains that sales, rather than plant investment, now determines how much distribution taxes the utilities pay. Under the current law, changes in the amount of plant in service for a utility do not affect the amount of distribution tax paid. 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. Usage is clearly the driving factor for these costs. (Staff Ex. 30.0, pp. 19-20)

Mr. Stephens also seeks to integrate the Company's recent merger into his argument on the PURA tax issue. He notes that because of the merger, the distribution tax for the combined Company is charged at a higher marginal rate than for the three legacy utilities. Thus, Mr. Stephens contends "that the PURA tax does not vary exclusively with kWh sales" because Ameren's PURA tax increased by $2.6 million with no change in sales. (*Id.*, pp. 27-28) The argument is not persuasive because it again fails to consider the fact that sales are the sole driver of these costs and the only effect of the merger is to change the rate at which those sales are taxed. The increase provides no support for Mr. Stephens' alternative plant-based allocator because the PURA tax rose even though the merger did not increase the level of plant on the system. (Staff Ex. 30.0, pp. 20-21)

Finally, Mr. Stephens' proposal for an alternative allocation of PURA taxes was rejected by the Commission in the most recent cases for Ameren (Docket Nos. 09-0306, et al (Cons.)) and ComEd (Docket No. 10-0467). Mr. Stephens offers no compelling new evidence in this proceeding for the Commission to deviate from those decisions. (Staff Ex. 30.0, p. 21)

In sum, Mr. Stephens' testimony on this issue is not persuasive and his alternative proposal for recovery of these costs should be rejected.

b. Minimum Distribution System (MDS)

The proposal by IIEC witness Stowe to adopt a minimum system approach for distribution plant is without merit and should be rejected by the Commission.

The proposal suggested by IIEC witness Stowe would allocate on a per customer basis the distribution plant that may be "attributable to minimum electrical industry mandated safety and reliability requirements for distribution facilities" (IIEC Ex. 2.0, p. 10) and thereby shift cost responsibility away from larger to smaller customers on the system. (Staff Ex. 30.0, p. 22)

Mr. Stowe justifies a per customer approach for these safety and reliability costs because they are incurred to serve customers without regard to their electricity demands. He contends that those costs are incurred whenever Ameren adds a new customer to its system. (*Id.*) According to Mr. Stowe, "[g]iven that the principal reason to extend the distribution system is to serve additional customers, it is only reasonable to conclude that the costs associated with meeting the requirements of the NESC vary with the number of customers." (IIEC Ex. 2.0, p. 12)

This argument is illogical. Clearly, Ameren must make a number of investments to maintain the safety and reliability of the system. However, those investments do not just occur when Ameren extends the distribution system to serve additional customers; it makes them for existing customers as well. Furthermore, the impetus for reliability and safety investments comes from the electricity that flows through the distribution system. As such, these safety and reliability concerns arguably support the allocation of a share of distribution plant on a per-kWh basis. (Staff Ex. 30.0, p. 23)

Mr. Stowe's minimum system argument suffers from a number of other deficiencies. For one, he incorrectly assumes that Ameren extends "its primary and/or secondary distribution system each time an additional customer connects to its system."

(IIEC Ex. 2.0, p. 13) In fact, new customers can be added without the need to extend either the primary or secondary system. Distribution lines can run alongside undeveloped land where, if development were to take place, there would be no need to extend the distribution system to serve the new customer or customers. (Staff Ex. 30.0, p. 24)

It is not true that safety and reliability investments are only made to to extend the system to connect new customers. As Mr. Stowe acknowledges, the utility also incurs investments to maintain reliable service for existing customers. (Tr., September 15, 2011, p. 725) However, his minimum system approach does not distinguish between those two sets of costs, but would instead apply the minimum system approach to both. (Tr., September 15, 2011, p. 726-727) This would clearly distort cost allocations because Mr. Stowe has provided no evidence that the minimum system is appropriate to use for distribution investments to serve existing customers.

This proposal by Mr. Stowe has already been considered and rejected by the Commission in a ComEd delivery services case (Docket No. 07-0566, IIEC Ex. 3.0, pp. 27-42). (Staff Ex. 30.0, p. 25) Given the weight of evidence, the Commission should reach the same conclusion on the proposal in this case as well.

c. Single/Dual-Phase v. Three-Phase

The proposal by IIEC witness Stowe to exempt primary customers from cost responsibility for single phase lines is unfounded and should be rejected by the Commission.

Mr. Stowe acknowledges that he raised this issue in ComEd's last rate case (Docket No. 10-0467) and the Commission rejected his argument because IIEC failed to provide evidence refuting Staff's criticisms of its proposal. However, he claims to have found new evidence in this case that addresses the Commission's concerns expressed in Docket No. 10-0467. Therefore, he claims to have justification for not allocating single phase primary line costs to primary service customers. (IIEC Ex. 2.0, p. 37)

One piece of evidence cited by Mr. Stowe concerns Ameren's line extension policy which provides "free extension equivalent to the cost of 250 feet of single-phase circuit" for both residential and nonresidential customers. According to Mr. Stowe, these tariffs "ensure that [Ameren] will incur the same level of cost in serving low usage secondary customers as it does in serving high usage primary customers, since all costs above the allowed line extension cost are charged directly to the new customer." (*Id.*, p. 39) Mr. Stowe then argues that because line extension rules are based "on the cost of a segment of single-phase circuit, Ameren's tariffs ensure it will incur the same level of cost in serving a three-phase customer as it does in serving a single-phase customer." (*Id.*, pp. 39-40)

The flaws in Mr. Stowe's conclusion about this policy are revealed by a simple example. Under this proposed line extension policy, two customers, one primary and another secondary, that are both situated 250 feet from an existing three-phase line would receive the same free extension of a single-phase line from Ameren. The one difference is that if the primary customer required three-phase service, he would have to pay an additional amount to upgrade that extension to a three-phase service. Nevertheless, in both instances the utility pays the same amount in distribution line costs to connect the primary and secondary customers to the system. Even though it costs the utility the same to serve both customers, Mr. Stowe argues that they should be allocated different distribution line costs because the primary customer is not receiving service from a single-phase line.

This argument clearly conflicts with cost causation principles. (Staff Ex. 30.0, pp. 27-28) The more appropriate conclusion is that the Company's line extension policy treats primary and secondary customers alike with respect to the costs Ameren is willing to incur to connect them to the distribution system because it is willing to incur the same cost to connect each to the distribution system. This would argue for equal, rather than unequal, treatment in the cost allocation process. (Staff Ex. 30.0, p. 28)

The second piece of evidence cited by Mr. Stowe concerns the relative cost of installing single-phase and three-phase lines. Mr. Stowe references data from Ameren indicating "that some single-phase installations are actually more costly than some three-phase installations." According to Mr. Stowe, this data "cast[s] doubt on the notion of 'the additional cost of a three-phase line' discussed in the Commission Order in Docket No. 10-0467." (IIEC Ex. 2.0, pp. 38-39) Based on these relative costs, Mr. Stowe contends that "blanket generalizations about the relative cost of circuit installation cannot be made based solely on the number of phases of the circuit." (*Id.*, p. 43)

Whether certain single-phase installations are more costly is irrelevant because no one argues that primary customers should be allocated <u>more</u> distribution costs than secondary customers. The issue is whether they should be allocated <u>fewer</u> costs as IIEC proposes and the fact that some three-phase costs are lower than single-phase costs does not justify a smaller cost allocation for primary customers. (Staff Ex. 30.0, p. 29)

Finally, Mr. Stowe opines that three-phase circuits are generally accepted as the backbone of all utility systems that serve both primary and secondary customers. He states that "[s]ince three-phase circuits are essential to any distribution system, and since many secondary voltage customers require three-phase service, one cannot assume that a utility has the flexibility to install single-phase supply circuits simply because the customers being served take service at secondary voltages." (IIEC Ex. 2.0, p. 42) According to Mr. Stowe, "[t]his information generally refutes the assertion that a utility could avoid the cost of a three-phase circuit simply because customers take service at secondary voltages." (*Id.*, p. 39)

Mr. Stowe's point is unclear. It is certainly true that the Company sometimes lacks the flexibility to install single-phase service and, as a result, installs three-phase service instead. However, the issue in this case is not three-phase, but single-phase lines. When the Company does have the flexibility to install single-phase lines, Mr. Stowe himself acknowledges that the characteristics of three-phase customers limit that flexibility. According to Mr. Stowe, "it is well known in the electric utility industry that certain phase/voltage combinations can lead to localized load imbalances (asymmetry), which can cause voltage instabilities." (*Id.*, p. 37) Furthermore, the fact that the primary customer's characteristics limit the utility's option does not reduce their contribution to system costs, but rather, in all likelihood, has the opposite effect.

Thus, the IIEC's position on this issue lacks merit and it should be rejected as in ComEd's last rate case (Docket No. 10-0467). (Staff Ex. 30.0, pp. 29-30)

VI. REVENUE ALLOCATION

A. Overview

Staff presents the most reasonable class revenue allocation in this proceeding and recommends that its approach be adopted. Staff's approach appropriately accounts for the limitations of the Rate Zone ECOSSs provided by Ameren and presents the proper balance of cost and non-cost factors in the development of class revenues.

B. Resolved Issues

1. Gas

a. Allocation of Revenue Requirement Across Rate Zones and Customer Classes

Staff and the Company have agreed on a reasonable approach to class revenue allocations and that approach should be adopted in this case.

In direct testimony, Staff initially recommended rejection of the Company's proposed gas class revenue allocations and gas rate design because they relied on Ameren's Initial gas ECOSS which was fundamentally flawed. (Staff Ex. 15.0, p. 5) Instead, for allocation of revenues to the gas rate zones, Staff proposed moving half the distance from equal percentage, across-the-board increases to fully cost-based revenue allocations for the three gas rate zones in the Company's deficiency Rate Zone ECOSSs. Furthermore, for allocation of revenues to each gas customer class within each of the gas rate zones, Staff proposed applying an across-the-board, equal percentage increase equal to the base revenue percentage increase for the corresponding gas rate zone as a whole. (*Id.,* p. 5)

The Company revised its deficiency Rate Zone ECOSSs in its rebuttal testimony to address Mr. Rukosuev's concerns regarding the FERC account balances that he found problematic. The Company provided percentages and comparisons of the individual FERC accounts by Rate Zone per its revised gas Rate Zone ECOSS. The changes delineated in the testimony of Mr. Stafford and Ms. Althoff addressed the concerns presented in Mr. Rukosuev's direct testimony. The Company employed consistent data from September 30, 2010, to derive rate zone balances not only at the functional level, but at the FERC account level as well. The revised gas Rate Zone ECOSSs address discrepancies at the subfunctional level within individual FERC accounts by developing revised figures to address those shortcomings. (Staff Ex. 31.0, p. 6)

Based on Staff's review in the rebuttal stage of this proceeding, the revised gas Rate Zone ECOSSs individual FERC account allocation were consistent with those used in Ameren's previous rate case (Staff Ex. 31.0, p. 14), thus, alleviating a significant concern expressed by Mr. Rukosuev in his direct testimony.

Staff's recommendation is based on the revised gas Rate Zone ECOSS, and consists of two steps. First, Staff recommends that at the Rate Zone level, Ameren's rates should , move half the distance from equal percentage, across-the-board increases to full cost-based revenue allocations for AIC's Rate Zones.[49] Second, at the rate class level, Staff recommends that the Commission accept the Company's proposed modification to Mr. Rukosuev's rate design, specifically, the Company's proposal to move individual rate classes toward cost based rates subject to a constraint that no class exceeds an increase of 1.50 times the overall average increase allocated to the respective rate zone. (*Id.,* pp. 1-2)

[49] In direct testimony Mr. Rukosuev's recommendation regarding moving half the distance from equal percentage, across-the-board increases to full cost-based revenue allocations for AIC's Rate Zones was based on the three Rate Zone ECOSSs provided in response to the ALJs deficiency letter, In rebuttal testimony Mr. Rukosuev recommended the same approach except that it was now based on Ameren's revised Rate Zone ECOSS.

b. Rate Moderation

In direct testimony, the Company proposed a capping mechanism ("Rate Moderation") that constrains movement to full class cost of service for any one class. The Company proposed that the percentage revenue increase for any one class be limited to 1.5 times the overall percentage revenue increase for AIC gas. Further, for an individual class within each rate zone, the Company proposed that the percentage revenue increases be limited to 1.25 times the percentage revenue increase for the whole AIC class. According to the Company, the application of these two constraints would allow for movement toward cost-based rates overall and by rate zone. (Ameren Ex.13.0G, pp. 13-14)

Staff explained that the Company's rate moderation proposal is flawed and should be rejected by the Commission as a basis for setting rates in this case. Staff demonstrated that the Company's deficiency gas Rate Zone ECOSSs contained a number of errors and conceptual flaws that rendered them unreasonable tools for designing rates. As a result, Ameren's allocation of costs to customer classes did not reflect actual cost causation. (Staff Ex. 15.0, p. 19)

The Company subsequently revised its Rate Zone ECOSSs in its rebuttal testimony to address Staff witness Mr. Rukosuev's concerns. Also, Company witness Althoff revised her rate moderation proposal. Specifically, the Company used the results of its revised gas Rate Zone ECOSSs rather than a single AIC cost of service study (or the deficiency three gas Rate Zone ECOSSs) to allocate revenue to Rate Zones and individual classes within Rate Zones. Next, Ms. Althoff accepted Mr. Rukosuev's proposed revenue allocation to the Rate Zones that moves "half the distance from equal percentage across-the-board increases to fully cost-based revenue allocations." (Ameren Ex. 33.0, pp. 11) Finally, Ms. Althoff proposed a modification to Mr. Rukosuev's proposed revenue allocation to customer classes within each of the rate zones by moving individual rate classes toward cost based rates subject to a constraint that no class increase exceed 1.50 times the overall average increase allocated to the respective rate zone. (*Id.,* p. 12)

In the Company's last rate case, the Commission noted a desire to eliminate rates that differ from cost of service, and stated "Continued movement toward cost-based rates and the elimination of inter- and intra-class subsidies should be considered a priority in AIU's next rate filing." (Order, Docket Nos. 09-0306, et al. (Cons.), April 29, 2010, p. 260) Hence, the application of the Company's revised rate moderation proposal in rebuttal testimony factors the desire to move toward cost-based rates and provides a level of rate mitigation, while still allowing prices to gradually increase toward rate uniformity among the Rate Zones. (Staff Ex. 31.0, p. 12)

In sum, the 150% constraint represents a reasoned judgment of how much progress can be made toward cost-based revenue allocations while addressing bill impact concerns. Ameren's modified Rate Moderation proposal will slow the implementation of full cost of service rates for some classes; however, it will lessen the impact of the rate increase for many Ameren customers. Therefore, Staff recommends that the Commission approve the revenue constraint that Ameren proposed in its rebuttal testimony for its gas operations (Staff Ex. 31.0, p. 13)

C. Contested Issues

1. Electric

a. Allocation of Revenue Requirement Across Rate Zones

Staff proposes the most reasonable approach to class revenue allocations and recommends that its approach be adopted in this case.

In its initial filing, Ameren proposed a two-step revenue allocation process based on the results of a single Illinois-wide ECOSS. That approach first allocated the revenue requirement to the three rate zones and then to customer classes within each of the zones solely based on a system-wide ECOSS. Rate mitigation was factored in because the proposal limited increases for any rate class to a maximum of 1.5 times the system average increase. (Ameren Ex. 13.0E, p. 12) The Company declined to adopt any additional constraints for customers at the subclass level. In addition, Ameren proposed movement toward uniformity, subject to the limitation that no class within a rate zone receives more than 125% of the average increase for the class. (*Id.*, p. 12) (Staff Ex. 14.0, pp. 16-17)

This approach is fundamentally flawed because it relies on a single Illinois-wide ECOSS rather than three Rate Zone ECOSSs as required by the Commission in its Final Order for Docket No. 10-0517. (Staff Ex. 14.0, pp. 17-18)

Staff, in turn, presented an alternative allocation of the revenue requirement among rate classes that more appropriately reflects the Commission perspective on costs for the Ameren system. That approach first allocates to the rate zones and second to rate classes within those rate zones. For allocation to the rate zones, Staff proposes moving half the distance from equal percentage, across-the-board increases to fully cost-based revenue allocations for the three rate zones in the Company's Rate Zone ECOSS. In allocating to the customer classes within rate zones, distribution taxes are removed from base rates for separate collection by an equal per-kWh charge on all usage by retail customers. Then, the remaining base revenues are allocated to rate classes on an equal percentage, across-the-board basis. Staff's proposed allocation methodology is presented in Schedule 14.04. (Staff Ex. 14.0, p. 18)

Staff's approach is reasonable because it appropriately considers the limited value the Company's ECOSSs can play in the class revenue allocation process. Staff has determined that the deficiency Rate Zone ECOSSs are useful for assessing overall cost recovery by the rate zones, but not for determining class cost responsibility within the rate zones. In the absence of a useful cost foundation at the customer class level, the most reasonable and equitable approach entails allocating base revenues to the rate classes on an equal percentage, across-the-board basis. Without a viable cost justification more to one class than another, the most reasonable approach is to give all classes an equal percentage increase. (Staff Ex. 14.0, p. 19)

In rebuttal testimony, Company witness Jones stated that Staff's proposed rate changes "move in similar direction to what AIC proposed in its direct case." However, he took issue with Staff's proposed across-the-board, equal percentage allocation within the rate zones to customer classes. Mr. Jones contends a cost-based approach should be used because Ameren's rebuttal cost of service studies correct the shortcomings identified in Staff's direct testimony. (Staff Ex. 30.0, pp. 6-7)

Mr. Jones also revised his class revenue allocations in rebuttal testimony. First, he chose a different cost foundation, replacing the single, Illinois-wide ECOSS with the three revised rebuttal Rate Zone ECOSSs. (Ameren Ex. 31.0, pp. 2, 4) Then, he adopted Staff's proposed revenue allocation to the rate zones that moves half the distance from equal percentage across-the-board increases to fully cost-based revenue allocations. However, for customer classes within the rate zones, Mr. Jones continued to advocate cost-based class revenue allocations constrained to a maximum of 1.5 times the rate zone increase or 10%, whichever is greater. (Ameren Ex. 31.0, p. 4)

Mr. Jones' proposed allocation to the rate classes is problematic because, as previously noted, the Company's revised Rate Zone ECOSSs that it provided in rebuttal testimony cannot be verified as reasonable for ratemaking in this case. The more reasonable Staff approach that appropriately considers the limitation of those studies features full recovery of distribution taxes on a volumetric basis and an equal percentage, across-the-board allocation within the rate zones of remaining base revenues. (Staff Ex. 30.0, pp. 5-6)

IIEC witness Mr. Stephens, presented an alternative perspective which focused on Ameren's proposed mitigation strategy for class revenue allocations. He criticized the Company for proposing to apply a 1.5 times system average increase constraint at the class, but not the subclass, level, contending that the Company proposal conflicts with the Commission decisions in Ameren's previous case (Docket Nos. 09-0306, et al. (Cons.)). (IIEC Ex. 1.0, pp. 6-7) Mr. Stephens further contended that Ameren's approach creates inordinate increases for individual large DS-4 customers as high as 494.4%. He considered these increases problematic and recommended that the Commission adopt the same rate moderation approach it approved in Ameren's last rate case, which applies the 1.5 times system average constraint down to the subclass level. As Mr. Stephens noted, this would ensure that no zonal subclass receives more than a 10.87% increase in delivery service rates. (*Id.*, p. 10) At the same time, Mr. Stephens acknowledged that his mitigation proposal could "slow movement toward" cost-based rates. (Staff Ex. 30.0, p. 16)

Mr. Stephens' proposal presents a problem from a cost standpoint because it would delay the attainment of cost-based rates. The significant differences in increases resulting from the Company and IIEC proposals (maximums of 494.4% vs. 10.87%) reveal the extent to which Mr. Stephens' recommendation would impede progress towards costs. (Staff Ex. 30.0, pp. 16-17)

Furthermore, this go-slow argument by Mr. Stephens' is inconsistent with previous statements he presented on the issue of cost-based rates. In the 2007 Rate Design Investigation for Ameren (Docket No. 07-0165), Mr. Stephens stated on the issue:

> Q. ARE THERE EVER CIRCUMSTANCES THAT MIGHT WARRANT A DEPARTURE FROM COST-BASED RATE PRINCIPLES?
>
> A. Yes, there can be. But they are the exception not the rule. The Commission should stick to the establishment of cost-based rates to the fullest extent possible. To do otherwise sends improper price signals and is fundamentally unfair. Any deviation from a cost basis should be directly attributable to events that provide compelling justifications for temporary excursion from cost. (IIEC Ex. 1.0, p. 5)

It is difficult to reconcile Mr. Stepehen's current proposal with his previous position that "[t]he Commission should stick to the establishment of cost-based rates to the fullest extent possible" and his further claim that "[t]o do otherwise sends improper price signals and is fundamentally unfair." (Staff Ex. 30.0, pp. 17-18)

b. Allocation of Revenue Requirement Across Customer Classes

See above section for all discussion regarding Allocation of Revenue Requirement Across Customer Classes.

c. Rate Moderation

i. Application of Rate Moderation at Rate Class and Subclass Levels

ii. Inclusion of PURA/Distribution Tax in Rate Moderation

Staff presents the most reasonable approach to recovery of distribution taxes in this docket, and Staff's approach should be adopted by the Commission. Staff's approach would address ongoing subsidies pertaining to the tax and would not unduly burden Ameren ratepayers.Staff's approach would eliminate the current inequity in which large customers fail to pay their full share of these costs and fully recover distribution taxes from all ratepayers through an equal per-kWh charge. (Staff Ex. 14.0, p. 19) Staff's approach would align the recovery of distribution taxes with cost causation and make the Ameren approach consistent with the methodology the Commission approved in ComEd's last rate case, Docket No. 10-0467. In that case, the Commission stated:

> In light of the Commission's prior treatment of the Illinois Electricity Distribution Tax in the Ameren Order, the Commission adopts ComEd's proposal to modify its rate design to provide a separate volumetric charge for the recovery of the Illinois Electricity Distribution Tax and uncollectible costs associated with the application of the tax for all of the reasons stated herein. (Final Order, Docket No. 10-0467, May 24, 2011, p. 285)

Staff's proposal to recover distribution taxes through a single per-kWh charge to all ratepayers would disproportionately impact large customers because of their failure to pay their fair share in the past. This can produce revenue increases as high as 47.44% for the Rate Zone II DS-4 class. (Staff Ex. 14.0, p. 20)

While these percentage increases would appear to suggest that Staff's proposal unreasonably burdens the DS-4 class, closer inspection demonstrates that is not the case. First, even with Staff's proposed increases, DS-4 customers in Rate Zones I and II would pay less than a half cent per kWh of electricity delivered, while they would pay .5161 cents per kWh in Rate Zone III on average. Even the average increase of 47.44% for Rate Zone II DS-4 customers corresponds to an increase of only 1.5 tenths of a cent per kWh. (*Id.*, p. 21). Furthermore, these rates for DS-4 customers compare quite favorably with distribution rates paid by High Voltage ComEd customers. In ComEd's last rate case (Docket No. 10-0467), High Voltage customers paid an average of more than 2.6 cents/kWh ($13,416,813/4,992,274,765 kWh[50]) for delivery service even before the higher rates went into effect as the result of the Final Order for Docket No. 10-0467. Thus, Staff's proposed rates would leave the average price per kWh for DS-4 customers at less than 20% of the average price for customers in ComEd's High Voltage class. (*Id.*, p. 21)

[50] $13,416,813 from Schedule E-5(a), p. 3 of 9; 4,992,274,765 kWh from ComEd Ex. 16.3, p. 2.

There is further good reason to move to full recovery of distribution taxes through an equal per-kWh charge in this docket. It should be remembered that the change to an assessment based on usage resulted from passage of the 1997 Amendatory Act (35 ILCS 620/1a, P. 90-561, eff. 1-1-98). Because they still do not pay their fair share today, DS-4 customers have received a distribution tax subsidy from other ratepayers for more than thirteen years. Given this accumulation of benefits at other ratepayers' expense, it is only reasonable that DS-4 customers finally be required to pay their full share of these costs. (*Id.*, p. 22)

VII. RATE DESIGN

A. Overview

B. Resolved Issues

1. Electric/Gas

a. Billing Units

2. Electric

a. BGS-1/BGS-2 Pricing

BGS-1 Pricing

Staff and Ameren Illinois agree that the issue of adjustments to BGS-1 prices is settled.[51] The goal of tying rates to a cost basis should be applied to AIC's electric

[51] AIC Ex. 48.0, p. 14.

supply rates, as well as AIC's delivery service rates.[52] Unlike the setting of the delivery service rates, the setting of the retail supply rates of the utility have a profound effect on retail customer competition from other providers. Consistent with this consideration, Staff recommends the elimination of subsidies to certain non-summer electric supply (BGS-1) rates, with annual adjustments to supply rates beginning June 1, 2013. (Staff Ex. 32.0, p. 1) The Company agreed with Staff's proposal, but recommended some revisions to Staff's proposals regarding the supply rates adopted to go into effect at the conclusion of this rate case. Specifically, the Company recommended adding three customer profiles to the profiles identified by Staff for revisions. Staff has no objection to these additions. Furthermore, the Company proposed to limit rate increases for the combined total of delivery service and BGS-1 price changes to 7.5%.[53] Staff noted that setting the cap at 7.5% for increases in both delivery service and supply rates arising out of this rate case leaves little room towards eliminating subsidies inherent in the non-summer tail block rates.[54] In addition, Staff's proposal for supply rate changes going forward does not contain any further movement towards cost-based non-summer rates until October 2013, something Mr. Jones agrees with.[55] For these reasons, Staff recommends that the Commission accept Mr. Jones proposal to take into account the delivery service rate changes coming out of this rate case, but it should cap the total bill impact for any of the 12 customer profiles at 10% instead of Ameren's proposed 7.5%.[56] AIC witness Jones agreed with this proposed modification.[57] Finally, the Company recommended that the tariff "invite a Commission review period for adjustments to non-

[52] Staff Ex. 16.0, p. 2.
[53] Ameren Ex. 31.0, p. 20.
[54] Staff Ex. 32.0, p. 4.
[55] Ameren Ex. 31.0, p. 27.
[56] Staff Ex. 32, p. 4.
[57] Ameren Ex. 48.0, p. 12.

summer prices after each IPA procurement event concludes prior to each summer."[58] Staff does not object to such a process for the annual BGS-1 adjustments recommended in this case.[59]

In sum, Staff and Ameren agree on the changes to the rate design for BGS-1 charges. Staff also agrees that Ameren Exhibit 48.1, which provides a revised redline/strikeout of Rider PER – Purchased Electricity Recovery (Rider PER), contains the necessary tariff changes to accommodate the provisions agreed to by Staff and AIC.

BGS-2 Pricing

Ameren proposed to eliminate the non-summer tail block rate for Rate Zones I and III. Ameren noted that the tail block was eliminated for Rate Zone II in the Company's previous rate case (Docket Nos. 09-0306 et al.). Further, Ameren proposed to set uniform prices of 7.059 cents/kWh for the summer and 5.639 cents/kWh for the non-summer period.[60] Staff recommended that the Commission accept these proposals.[61] The fact that the declining block has already been eliminated for Rate Zone II demonstrates that it is a realistic goal for the class. Further, the significant difference between summer and non-summer supply prices should limit adverse impacts for individual customers from implementation of this proposal. In addition, Ameren's argument about the uniformity of the underlying costs provides a compelling basis for moving towards a uniform supply charge.[62]

[58] *Id.*, p. 27.
[59] Staff Ex. 32.0, p. 6.
[60] Ameren Ex. 13.0E, p. 36. These values still reflect the 2010/2011 BGS levels that have been updated as of June 1, 2011.
[61] Staff Ex. 16.0, p. 15.
[62] *Id.*

b. Rebalancing DS-3 +100 kV/High Voltage Delivery Charges

c. DS-3/DS-4 Rate Limiter

3. Gas

a. Increase for Charges (Except GDS-1 and GDS-5)

The Company's only proposed change to the Rate GDS-1 tariff reflects its proposed revenue requirement. For Rate GDS-1, the determined constrained revenues by rate zone were split into Customer Charge and Delivery Charge revenues. The individual rate zones' Customer Charge revenues were then divided by the respective number of customer bills in each rate zone to derive the proposed monthly Customer Charge. The residual Delivery Charge revenue for each rate zone was then divided by the annual therms to derive the per unit Delivery Charge. (Ameren Ex. 13.0G, p. 18)

AIC proposes no tariff charge changes to the Rate GDS-3 tariff other than to adjust rates to reflect its proposed revenue requirement. The monthly Customer Charges and two Delivery Charges for Rider S and Rider T were increased based on the percent increase determined in the constrained revenue determination presented in Ameren Exhibit 13.6G. (*Id*., p. 19)

Also, AIC proposes no tariff charge changes to the Rate GDS-5 tariff other than to adjust rates to reflect its proposed revenue requirement. (*Id.*, p. 22)

For discussion related to increases for Rate GDS-2 and Rate GDS-4, please see section VII.C.3.c

In keeping with the Rate Moderation proposal as discussed in section VI.C.1.c.i., Staff supports adoption of the Company's Rates GDS-1, GDS-3, and GDS-5 rate design proposal.

b. Single PGA/Rider PGA

AIC proposes to adopt a single PGA tariff covering its service area. Currently, there is a separate PGA tariff for each of three rate zones, which correspond to the three legacy utilities – Rate Zone I (AmerenCIPS), Rate Zone II (AmerenCILCO), and Rate Zone III (AmerenIP). The operational benefits anticipated by the Company were addressed by Staff witness Lounsberry in his testimony. (Staff Ex. 17.0, pp. 3-6) Staff witness Lounsberry reviewed Ameren's request and the benefits Ameren asserts would result from the use of a single PGA and found no reason to dispute Ameren's request. (Staff Ex. 17.0, pp. 4-5) The monetary effect on customers was addressed by Staff witness Jones. (Staff Ex. 6.0, pp. 3-10)

Based on analyses prepared by AIC and a separate analysis prepared by Staff witness Jones, Ms. Jones agrees with the Company that the monetary effect on customers of a single PGA tariff would be minimal. Ms. Jones also reviewed an analysis prepared by AIC of the impact a Demand Gas Charge ("DGC") would have on GDS-4 Rider S customers in Rate Zone I. Currently, there is no demand component in the rates charged to those customers as there is in Rate Zones II and III. However, under a single PGA, all GDS-4 Rider S customers would be subject to a DGC. The analysis indicates that all customers but one would have paid less over a 12-month period beginning November 2009 and ending October 2010. (Staff Ex. 6.0, pp. 5-6)

If a single PGA tariff is approved by the Commission, AIC proposes to freeze the over/under recovered balances for each legacy Rate Zone on the effective date of the single PGA. In addition to the single PGA rate, for a twelve-month period AIC will set rates by legacy Rate Zone to credit/charge the over/under recovered balances to the applicable customers. The Company will continue to track the outstanding balances and make a monthly PGA filing for the respective legacy Rate Zone until the balances are reduced to the point that an adjustment would no longer have a measurable impact on customers' bills. (*Id*., pp. 6-7)

Ms. Jones recommends that within the twelve-month time frame proposed by the Company, the process continue until the respective rate per therm cannot be set to four decimal places; i.e., is less than .01 cents per therm. The balance remaining when a rate can no longer be set, or at the end of the twelve-month period, should be rolled into the single PGA charge as an "Other Adjustment" on Schedule II of the respective PGA charge. Additionally, if it is necessary to continue the process of over/under recovery longer than two months, beginning in the third month the rates should be calculated at two-month intervals. (*Id*., pp. 7-8) On alternate months the rates should be set at $0.00. This allows time for the Company to better gauge the respective over/under recovered balance before the next billing month. (Ameren Ex. 35.2) AIC agrees with Ms. Jones' recommendations. (Ameren Ex. 35.0, p. 4)

If a single PGA is approved by the Commission, Ms. Jones recommends that the following language be inserted in Rider PGA that describes (1) how the outstanding over/under recovered balances on the effective date of the single PGA will be refunded to or collected from customers and (2) how potential over/under recoveries ("Factor O's") for prior reconciliation periods that may be ordered by the Commission, subsequent to implementation of a single PGA, will be addressed.

> Section A – Applicability of Rider PGA:
>
> During the transition period from rate zones to a single rate, a factor will be used to adjust up or down the single PGA rate so that each rate zone will receive or be charged its respective over/under recovered balances existing on the effective date of the single PGA. For a maximum twelve-month period subsequent to the effective date of the single PGA, the Company will separately track and calculate a rate on each outstanding balance until the rate is less than 0.01 cent per therm, at which time the remaining balance will be rolled into the respective single PGA charge as an "Other Adjustment" on Schedule II. If it is necessary to continue the process of over/under recovery longer than two months, beginning in the third month the rates shall be calculated at two-month intervals in order to permit the Company an opportunity to better gauge the respective over/under recovered balances before the next billing month.
>
> Additional over/under recoveries ("Factor O's") ordered by the Commission for PGA reconciliation periods prior to the implementation of a single PGA will be refunded/charged in the same manner described for outstanding over/under recovered balances on the effective date of the single PGA, if within the applicable twelve-month time frame. Subsequent to the twelve-month time frame, the Factor O's will be included in the calculation of the appropriate single PGA charge. (Staff Ex. 6.0, pp. 8-9)

AIC agrees with the recommended language changes. (Ameren Ex. 35.0, pp. 5)

Whether or not the Commission approves a single PGA tariff, AIC also agrees with Ms. Jones' recommendation to add language to Rider PGA that describes the type of costs included in the calculation of the DGC. (*Id*.)

> Section F(c) – Demand Gas Charge
>
> The Demand Gas Charge calculation shall include all demand or reservation costs paid to gas suppliers and pipelines for gas supplies and transportation capacity, all leased storage costs, and any other fixed costs of gas supply that meet the definition of recoverable gas costs in Section D apportioned to Customers receiving the Demand Gas Charge. (Staff Ex. 6.0, p. 10)

c. Conformity of GDS-2 Customer Charge – 600 Therms

In direct testimony, Staff expressed its concerns that the rate design presented in the Company's direct testimony was not based on individual Rate Zone ECOSSs and regarding the accuracy of the costs presented at the FERC account level which were determined in a different way than in previous ECOSSs for the three legacy utilities. (Staff Ex.15.0, p. 14) Therefore, Staff recommended rejection of the Company's proposed class revenue allocations and rate design for GDS-2 because they relied on Ameren's Initial gas ECOSSs which were fundamentally flawed. (*Id.*, p. 5) In response to Staff's concerns, the Company provided revised gas Rate Zone ECOSSs that used individual FERC account allocations consistent with those used in its previous rate case. (Staff Ex. 31.0, p. 14)

By presenting its corrected Rate Zone ECOSSs in the Company's rebuttal, the Company did not leave sufficient time for all parties to fully review the accuracy of the revised three gas Rate Zone ECOSSs and determine whether Ameren's proposed rates were reasonable from a cost standpoint. Nevertheless, Staff evaluated what rate design proposals would be most reasonable for Ameren customers even without the benefit of an ECOSS foundation. (*Id*., p. 15)

The Company's proposal to revise the customer charge tier structure for GDS-2 was supported by a number of arguments presented by Company witness Althoff as follows: 1) as a means to mitigate undue customer impacts for smaller use GDS-2 customers in Rate Zone III; 2) the proposed rate structure will generate revenues from customers which more closely align with the cost to provide service while maintaining the provision to recover 80% of GDS revenue requirement from the Customer Charge approved in ICC Docket Nos. 07-0585 - 07-0590 (Cons.); 3) the Company may experience additional customer complaints if the existing GDS-2 design is retained for Rate Zone III; and 4) customers faced with cost based prices are more likely to make more efficient consumption decisions. (*Id.*, 15-16)

Staff recommends that the Commission approve the changes to GDS-2 to conform the GDS-2 Customer Charge rate structure for Rate Zone III to that of Rate Zones I and II. The Company's rate design proposal is in the best interest of its customers. It is a generally held ratemaking policy that rates should be designed to reflect cost causation, gradualism, and avoid rate shock. Staff understands that the Company wishes to mitigate the impact of any rate increase stemming from this proceeding. Staff also agrees that taking steps toward implementing cost-based rates while attempting to minimize rate shock is appropriate. (*Id*., p. 16)Hence, despite the remaining problems with the Company's revised Rate Zone ECOSSs due to timing issues as discussed previously, Staff supports adoption of the Company's GDS-2 rate design proposal. (*Id.*, p. 16)

d. Conformity of GDS-4 Customer Charge – MDCQ

In direct testimony, Staff expressed concerns that the rate design presented in the Company's direct testimony was not based on individual Rate Zone ECOSSs and regarding the accuracy of the costs presented at the FERC account level which were determined in a different way than in previous ECOSSs for the three legacy utilities. (Staff Ex.15.0, p. 14) Therefore, Staff recommended rejection of the Company's proposed class revenue allocations and rate design for GDS-4 because they relied on

Ameren's Initial gas ECOSSs which were fundamentally flawed. (Staff Ex. 15.0, p. 5) In response to Staff's concerns, the Company provided revised gas Rate Zone ECOSSs that used individual FERC account allocations consistent with those used in its previous rate case. (Staff Ex. 31.0, p. 14)

In rebuttal testimony, the Company provided additional arguments supporting its proposed changes to rate GDS-4. The Company stated that the proposed rate structure better matches costs to cost causers and that intra-class subsidies will be reduced under the proposed rate design, in keeping with the Commission's Order in Docket Nos. 09-0306 - 09-0311 (Cons.). (*Id.*, pp. 19-20) The Company proposed to move Rate Zones I, II and III GDS-4 delivery rates toward price uniformity, consistent with the Commission's directive that AIC have uniform customer class rates wherever possible. (Order, Docket Nos. 09-0306 et al. (Cons.), April 29, 2010, p. 264) Specifically, the Company proposed that customer demand, rather than throughput, provides a superior price signal versus customer delivery volumes for such GDS-4 customers as demand matches the criteria used to plan and design facilities serving customers. As such, in the movement toward rate uniformity, the Company proposed to migrate toward one uniform demand charge versus the two currently in place for Rate Zone III. However, bill impacts prohibit this from occurring in this rate proceeding. (Ameren Ex. 13.0G, pp. 19-20)

Staff recommends that the Commission accept the Company's proposal to move Rate Zones I, II, and III GDS-4 toward price uniformity. The Company's rate design proposal for the GDS-4 customer class is in the best interests of its customers. Despite the problems with the Company's revised Rate Zone ECOSSs as discussed previously, Staff finds that the Commission's directive with respect to the GDS-4 customer class in Docket Nos. 09-0306 et al. (Cons.), and Ameren's subsequent evaluation and findings with respect to the GDS-4 customer class, provide a sufficient basis for adoption of this proposal. (Staff Ex. 15.0, pp. 20-21)

C. Contested Issues

1. Electric

Staff's proposed rate design is the only rate proposal that appropriately considers the lack of a viable cost foundation for ratemaking in this docket, and therefore should be approved by the Commission. The alternative proposals presented in this proceeding are based on flawed cost approaches and should not be adopted for ratemaking.

Ameren's rate design approach would "maintain the rate design convention in effect today." (Ameren Ex. 13.0E, p. 25) That includes setting meter charges "approximately equal" to cost; maintaining pricing uniformity across the rate zones for customer, meter and transformation charges and uniform changes to lighting fixture charges. (Ameren Ex. 13.0E, pp. 25-26) Ameren witness Jones contends that "[i]ndividual price changes are modest, and move toward the average cost for AIC." (Ameren Ex. 13.0E, p. 26) (Staff Ex. 14.0, p. 24)

For residential charges, Ameren proposes that customer charges be increased from $12.28 to $15.55 per month. Mr. Jones states that "[c]ombined with the Meter Charge, this represents a $3.00/month increase from $17.00/month to $20.00/month. (Ameren Ex. 13.0E, p. 31)

The Company filing offers little explanation for this level of increase. Mr. Jones indicates that “the combined total of the Meter and Customer Charge was increased by an above average amount so that changes to variable Distribution Delivery Charges could be minimized.” (Ameren Ex. 13.0E, p. 31) Only in response to discovery does the Company indicate this increase is somehow based on the straight-fixed-variable concept (Staff Ex. 14.0, p. 25)

For Residential delivery charges Ameren proposes a uniform percentage increase. (Staff Ex. 14.0, p. 25)

For Small General Service DS-2 customers, the Company also proposes significant increases in fixed charges combined with equal percentage increases in all delivery charges, consistent with its proposals for residential customers. (Id., p. 25)

For DS-3 and DS-4 customers, Ameren would maintain uniform customer charges between DS-3 and DS-4 and across the rate zones and reduce their levels below the current charges. While the Company does propose increases in meter charges, total fixed charges paid by these customers would be left at or below current levels. Thus, Ameren’s proposal for DS-3 and DS-4 customers diverges from its proposals for DS-1 and DS-2 customers who would receive significant increases in their fixed charges. (Ameren Ex. 13.0E, pp. 38-39, Schedule E-5) Ameren provides no explanation for these differing approaches to large and small customers.

In addition, Ameren proposes to maintain the transformation charge at its current level of \$0.65/kW (Ameren Ex. 13.0E, p. 39) and the reactive demand charge at \$0.29/kVAR. (Ameren Ex. 13.0E, p. 41) The demand charges were then adjusted to produce the desired class revenue requirement. (*Id.*, p. 42)

The Company's proposed delivery services rate design is fundamentally flawed. The starting point lies with the deficiency Rate Zone ECOSSs that Ameren prepared for the individual rate zones which suffer from fundamental flaws that render them unfit for ratemaking. The Company has failed to establish that its Rate Zone ECOSSs accurately reflect the cost of serving rate classes in the three rate zones. Thus, Ameren lacks a viable cost foundation for its proposed rate design in this case. (Staff Ex. 14.0, pp. 26-27)

In light of these shortcomings, Staff has developed the most reasonable rate design alternative for Ameren customers. Staff's proposal adopts an across-the-board, equal percentage increase on all existing base rate charges for all retail classes within each individual rate zone to produce a proposed revenue increase for the rate zone as a whole. Under this revenue allocation proposal, customer, meter, delivery, transformation and remaining charges for Rate Zone I customers would all increase by approximately 9.5%. Similarly, charges in Rate Zone II would rise by approximately 12.3%. For Rate Zone III, the charges would increase by approximately 5.0%. Staff's proposed rates under the Company's proposed revenue requirement for Rate Zones I, II and III are presented in Schedules 14.06, 14.07 and 14.08, respectively. (*Id.*, pp. 28-29)

Staff's alternative appropriately considers the lack of a viable cost foundation for rate design in this case. The lack of such a foundation makes it difficult to argue that one charge be increased by more or less than other charges faced by customers. The equitable approach in this situation would raise existing rate charges by an equal percentage amount. (Id., pp. 29-30)

By applying different percentage increases to charges for the three rate zones, Staff's proposal would move away from uniformity for individual charges. However, uniformity appears to be a non-issue for Ameren ratepayers. While they are likely concerned about the level of their bills, no evidence has been provided that ratepayers in a particular rate zone care whether they pay the exact same customer, meter or transformation charges as customers in another rate zone. (*Id.*, p. 30)

Uniformity in rate charges is most important to the Company. As such, Ameren bears the responsibility to provide the cost foundation for moving to uniformity. The deficiencies in Ameren's ECOSSs for this proceeding demonstrate that it has not fulfilled that responsibility. If Ameren comes to understand that further progress depends on the quality of its cost studies, that will incent Ameren to provide more reasonable studies in future cases. (*Id.*)

The failure to establish a reasonable cost standard is a problem of the Company's own making. The revised Rate Zone ECOSSs present less detail than the comparable studies Ameren prepared in previous cases when the Company maintained separate cost information for the AmerenCIPS, AmerenCILCO and AmerenIP service territories. The lack of data arises because Ameren decided to no longer maintain this level of cost detail. This denies the Commission access to reliable cost information that is essential for the ratemaking process. In short, the problem arises not because Ameren was unable to maintain this cost information but rather, because Ameren chose not to do so. It is important to signal to the Company that ratemaking remains the province of the Commission and that it is unacceptable for Ameren to take preemptive measures that limit the Commission's range of action. (*Id.*, pp. 30-31)

Furthermore, if the Commission were to approve a revenue requirement lower than the Company proposes, then Staff's proposed charges to recover base revenues for retail customers should be reduced on an equal percentage basis to conform to the revenue requirement for each rate zone adopted by the Commission at the end of this proceeding. This equal percentage approach should not be extended to costs associated with distribution taxes. Under all scenarios, those costs should be removed in their entirety from the revenue requirement for separate recovery through an equal charge applied to all kWhs delivered for retail customers to maintain consistency with the approach adopted in the ComEd case. (*Id.*, p. 31)

In rebuttal, Company witness Jones sought to defend Ameren's proposed rate design against Staff's criticisms. In response to Staff's concerns about basing rates on the results of a single Illinois-wide ECOSS, he argued that Ameren's proposals for uniform meter, customer, transformation and reactive demand charges do not require rate zone level ECOSSs to be adopted. He believes that "[f]or these price components, a single AIC study provides adequate cost foundation." (Ameren Ex. 31.0, pp. 8-9)

This justification for a single ECOSS conflicts with Mr. Jones' statement in rebuttal that "[t]he Final Order in Docket 10-0517 suggests that decisions to move toward single-tariff pricing should be based on individual Rate Zone cost of service determinations." (*Id.*, p. 2)

Staff does agree with Mr. Jones' statement that movement toward single-tariff pricing should be based on Rate Zone ECOSSs. However, the Company's failure to provide viable Rate Zone ECOSSs in its response to the ALJs' deficiency letter (see Staff Ex.14.0, pp. 11-15) signifies the lack of a cost foundation for moving towards uniform charges. (Staff Ex. 30.0, pp. 9-10)

Mr. Jones criticized Staff's equal percentage, across-the-board rate design proposal, claiming that it undermines the progress made towards uniformity while continuing to insist that certain price components can be based on "a single AIC cost of service study." Mr. Jones also contends that Staff's across-the-board approach fails to address the mismatch in DS-3 delivery charges which are higher for +100 kV customers than for High Voltage customers, despite the fact that High Voltage customers use more of the distribution system to receive service. He further asserts that Staff's approach produces incongruent results because Rate Zone III customers end up with the lowest customer and meter charges but the highest overall rates. He also argues that the approach "prolong[s] the subsidy to high non-summer use BGS-2 customers and to BGS-1 space-heat customers in Rate Zones I and III" as well as all as "large non-summer use customers in the Rate Zone II and the Metro-east region of Rate Zone I." Finally, Mr. Jones claims that Staff's concerns about the Company's Rate Zone ECOSSs have been addressed by Ameren in rebuttal testimony which obviates the argument for Staff's across-the-board, equal percentage approach to rate design. (*Id*., pp. 11-12)

Staff agrees with some but not all of Mr. Jones' arguments. One argument that is reasonable concerns the inconsistency in DS-3 distribution delivery charges between +100 kV customers and High Voltage customers. Since +100 kV customers use a smaller portion of the distribution system they should pay lower distribution delivery charges than High Voltage customers. With regard to his defense of the Rate Zone ECOSSs presented in Ameren's rebuttal, Staff does not fully accept Mr. Jones' argument. While they do provide a more reasonable foundation for ratemaking in this case than the previous ECOSSs, their appearance in rebuttal testimony afforded insufficient time (approximately a month to review and prepare testimony) to fully establish that they provide a reasonable cost foundation and to examine how those three Rate Zone ECOSSs can be incorporated into the ratemaking process. (*Id.*, p. 11)

One argument by Mr. Jones that does present a concern seeks to justify using a single Illinois-wide ECOSS to support uniform rates. Staff has previously explained the problems with that position. Staff also does not share Mr. Jones' concern about the relationship between the customer charge and overall rate level for Rate Zone III compared with the other rate zones. As will be discussed further, the circumstances of this case warrant such a ratemaking outcome. Staff also does not share Mr. Jones' concern that its proposal would move away from uniform rates. In this proceeding the Company provided rate design filings that could not be verified to be accurate. (Tr., p. 875, September 15, 2011) Under those circumstances, the most reasonable alternative is to adopt an across-the-board design of rates.

Not only is this approach the most reasonable alternative, it also provides the essential signal to the Company that it must provide reasonable cost data in a timely fashion to achieve its uniformity objectives. Here, it clearly has not done so. Ameren witness Jones noted in rebuttal that "[t]he Final Order in Docket 10-0517 suggests that decisions to move toward single-tariff pricing should be based on individual Rate Zone cost of service determinations." (Ameren Ex. 31.0, p. 2) However, the Company provided ECOSSs in this case that until the rebuttal stage, contained clear and obvious flaws. By submitting its rebuttal Rate Zone ECOSSs more than five months after the initial filing in this proceeding, Ameren did not leave sufficient time for all parties to conduct a thorough and meaningful review. This is especially important because the Company's proposals include significant increases in customer charges for residential and small commercial customers. The shortcomings in Ameren's ECOSSs have impeded the review and analysis of the Company's proposals and for this reason they should not be approved. Given the Company's delay in filing the rebuttal Rate Zone ECOSSs and the resulting inability of Staff and other parties to verify and respond to them, the most reasonable approach is to adopt Staff's proposed across-the-board rate design. The Commission should adopt Staff's rate design proposals. This approach is the best alternative to cost based rates given the the Rate Zone ECOSSs were provided to late to be subject to verification. This approach would also signal to the Company the need to provide reasonable Rate Zone ECOSSs on a timely basis if it wishes to significantly raise customer charges and make them uniform in the future. (Staff Ex. 30.0, p. 13)

a. Increase for Charges in General

b. Treatment of PURA/Distribution Tax Expense

i. Phase-in of PURA/Distribution Tax Expense

The Company's alternative proposal for the recovery of distribution taxes is flawed and should be rejected by the Commission. That approach employs a three-step phase-in to full recovery of distribution taxes over a three year period. The first step at the end of this docket would "modestly" move DS-4 distribution tax rates towards the rates paid by other rate classes, while the second step in February 2013 would remove 50% of the subsidy to DS-4 customers and adjust rates for other classes accordingly. Finally, in February 2014, the remaining subsidy would be eliminated and the same distribution tax rate would be assessed for all Illinois customers. (Ameren Ex. 13.0E, pp. 20-21) (Staff Ex. 14.0, pp. 22-23)

The Company's argument on this issue focuses on the need to eliminate the current tax subsidy. Ameren considers this an equity issue for rate classes that must subsidize DS-4 customers and notes that it could incur losses if underpaying DS-4 customers add incremental load. Ameren further notes that the mismatch between collections and costs is inconsistent with the Commission's characterization of the tax as a "pass-through" (Ameren Ex. 13.0E, p. 23) (Staff Ex. 14.0, p. 23)

These arguments support Staff's contention that the current distribution tax subsidy for large customers should be eliminated. However, they do not justify the Company's complex phase-in approach which would revise rates for all classes two times outside the rate case process. This could confuse ratepayers who might not understand why their rates are changing in both 2013 and 2014. (Staff Ex. 14.0, p. 23)

Another problem is that the Company's phase-in proposal would take an inconsistent approach to bill impacts. Ameren proposes to apply its constraint to all revenue changes at the conclusion of this case, including the first phase-in step for distribution taxes. However, Ameren's proposed changes to distribution taxes in 2013 and 2014 would fall outside this constraint. Thus, Ameren appears to be sending conflicting messages concerning the role of constraints in class revenue allocations. (Staff Ex. 30.0, pp. 7-8)

ii. Exclusion of PURA/Distribution Tax Expense from Base Rates

iii. Collection of PURA/Distribution Tax Expense as Separate Per kWh Charge on Bill

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> In light of the Commission's prior treatment of the Illinois Electricity Distribution Tax in the Ameren Order, the Commission adopts ComEd's proposal to modify its rate design to provide a separate volumetric charge for the recovery of the Illinois Electricity Distribution Tax and uncollectible costs associated with the application of the tax for all of the reasons stated herein. (Final Order, Docket No. 10-0467, May 24, 2011, p. 285)

c. DS-1 Customer Charge

d. DS-3/DS-4 Seasonal Rates

2. Gas

a. GDS-1 Customer Charge

b. GDS-5 – Expansion of Rate Class Availability

According to Ameren witness Althoff, the GDS-5 rate structure is unchanged from what is currently in effect. However, rates and charges are adjusted to recover the increased costs to serve this class based on revenue constraints. (Ameren Ex. 13.0G, p.16)

However, in direct testimony, Grain and Feed Association ("GFA") witness Mr. Adkisson presented a number of arguments concerning temperature-based pricing for a broader range of customers taking service under the GDS-5 rate. Mr. Adkisson argued that the benefits of the GDS-5 rate should be available to large, intermediate and small customers that are willing to curtail usage on days when the average temperature is equal to or below 25 degrees Fahrenheit. (GFA Ex. 1.0G, p. 3) Specifically, he believes that a GDS-2 and GDS-3 customer would not be inclined to pay more for their current delivery charges to avail themselves of the off-peak provisions of the GDS-5 rate. In contrast, GDS-4 Large General Service customers are more likely to switch since their current customer charges are "in the same range" as the GDS-5 customer charges. (Staff Ex. 31.0, p.24)

To address this alleged inequity, Mr. Adkisson proposed adding a new tier with a lower fixed charge within the GDS-5 rate for smaller off-peak customers to encourage greater utilization of the Company's distribution system. In his direct testimony, Mr. Adkisson prepared a redline version of AIC's proposed GDS-5 tariff (Ameren Exhibit 1.01G) which only has an additional tier for intermediate size GDS-3 customers. This, in turn, broadens the range of customer charges that are equal to the AIC proposed customer charges for GDS-3 rates in the respective rate zones. Mr. Adkisson stated, however, that he did not propose an additional tier for small GDS-2 size customers to allow for operational experience and an assessment of acceptance of the GDS-5 seasonal rate by GDS-3 intermediate size customers before considering whether to expand GDS-5 to GDS-2 small customers. (GFA Exhibit 1.0G, p. 4)

In rebuttal testimony, Staff expressed concerns about GFA’s proposal. First, GFA’s proposal has the potential to set back the attainment of cost-based rates. In addition, although Staff appreciates GFA's concerns for its members, Staff believes that implementation of GFA’s proposal would not be as straightforward as GFA suggests. (Staff Ex. 31.0, p. 25) The GDS-5 tariff is the tariff most applicable to GFA‘s members since it reflects the different impacts seasonal-use customers have on costs associated with gas delivery. The purpose of the GDS-5 tariff is to promote system reliability by discouraging gas use by individual customers whose operation on days when space heating demands increase would cause reliability issues. The GDS-5 rates are based costs; they reflect the different impacts that seasonal customers have on fixed and variable costs. (*Id.*, pp. 25-26)

Staff believes that the GFA fails to address the impact that its proposal may have on customers. In addition, the GFA fails to provide any substantive analysis of the rate or bill impacts of its proposal on the Company, its membership, or on any other customers. Despite proposing entirely new GDS-5 tier provisions for all three Rate Zones, Mr. Adkisson provides no meaningful analysis of the effects (i.e., rate design, cost allocation, bill impact analysis, customer rate migration, revenue instability, or cost analysis) of his proposed recommendation. (*Id*., p.26)

GFA's proposed modification is likely to lead to an inequitable assignment of costs among customer classes, because the Company already incorporates the different impacts that seasonal customers have on fixed and variable costs, and reflects those impacts in the billing components and associated charges of GDS-5. Without thorough analysis, the extent to which this change in rate design will affect the Company's cost recovery is unknown. To avoid the possibility of revenue erosion, a complete analysis of the affected service classifications to determine realignment of class billing determinants would be necessary. Such analysis would require assumptions for expected customer migration. In the absence of a thorough analysis, GFA's proposal would add ambiguity for rate administration, which would result in financial uncertainty for the recovery of a utility's approved revenue requirement. (*Id.*)

Staff believes that Ameren's proposed GDS-5 tariff charges are reasonable. Although under the Company's current GDS-5 tariff provisions, small and intermediate GDS-2 and GDS-3 customers might not financially benefit from switching to the optional GDS-5 tariff (because of the proposed high monthly fixed charges), this fact alone does not necessarily render the GDS-5 tariff unreasonable. The current GDS-5 rates are based on cost and no showing has been made that an additional tier would better capture the cost impacts of seasonal customers. The GFA's proposal would add ambiguity for rate administration, which would result in financial uncertainty for the recovery of Ameren's approved revenue requirement. In effect, the Commission would have to allow adjustments to other rates in order for the Company to make up any revenue shortfall created by GFA's proposal. (*Id.*, p.26-28)

In sum, Staff submits that GFA's simplistic proposal is unsupported. Insufficient analysis has been provided as to the impacts on costs for the customers or revenue for the Company. Without such analysis, it has been impossible to work through complex cost-of-service determinations. (*Id.*, p. 29) Therefore, Staff recommends that the Commission reject GFA's proposal to add an additional tier to GDS-5 across all rate zones.

VIII. PROPOSED RIDERS/TARIFF CHANGES

A. Overview

B. Resolved Issues

1. Electric/Gas

a. Combined Billing of Multiple Meters

b. Rider PER

c. Pensions Benefits Rider

In direct testimony, Staff proposed that the Commission reject the proposed Rider PBR. (Staff Ex. 3.0, pp. 25-26) In the rebuttal testimony of Mr. Nelson, the Company withdrew its request for a pension rider. (Ameren Ex. 21.0 (Rev.), p. 24)

d. Uncollectibles Rider (If Switched to Net Write-offs)

Staff recommended that the Commission order the Company to begin using the net write-off method instead of using Account 904 for the purpose of determining the utility's uncollectible amount in rates. Staff calculated the percentage of uncollectibles related to delivery services using the net write-off method for each respective electric and gas rate zone. (Staff Ex. 3.0, pp.6-11; Staff Ex. 21.0, pp. 8-12) The Company rejected Staff's proposal to switch to the net write-off method and the calculation of an individual percentage for each separate electric and gas rate zone. These issues are fully addressed in Operating Revenue and Expenses Section III. C. 1. regarding uncollectibles expense.

C. Contested Issues

1. Gas

a. Rider TBS – Transportation Banking Service

The Commission's Directive

Ameren's customers all take service under either Rider S or Rider T. Rider S customers purchase gas commodity exclusively from Ameren at the Purchased Gas Adjustment ("PGA") price each month and are referred to as sales customers. Rider T customers purchase gas commodity from suppliers and are referred to as transportation customers. Transportation customers nominate their pipeline deliveries separately from the utility, which is the agent for sales customers. Transportation customers can balance their deliveries against their usage by injecting excess deliveries into a "bank" and withdrawing their gas from the bank when deliveries are less than usage. In his direct testimony, Staff witness Sackett outlined three key bank characteristics: 1) the total amount of gas that it has stored (the bank inventory), 2) the total amount that it is permitted by the tariff to store (maximum storage capacity) and 3) the maximum quantities that customers can withdraw on a system peak day (peak day withdrawal rights). (Staff Ex. 13.0, p. 6)

During the last two rate cases, in 2007 and 2009, transportation service has taken its current form under Rider T. One issue that Staff raised in the 2009 rate case concerned the level of access that transportation customers had to Ameren's on-system storage. In particular, Staff argued that it should be proportional to system storage capacity. (Final Order, Docket Nos. 09-0306 et al (Cons.), April 29, 2010, p. 277) The Commission declined to make any changes in that docket, but ordered that Ameren and Staff participate in a workshop process. (*Id.*, p. 283)

In the 09-0306 Order, the Commission set in motion a process that would enable it to revisit these transportation service issues in this rate case. The Commission also required that Ameren provide tariffs implementing either the Nicor or Peoples method. (Staff Ex. 13.0, p. 6)

The Nicor Method

Ameren indicated it preferred the Nicor banking provisions rather than those of Peoples Gas and North Shore Gas. (Ameren Ex. 14.0G, p. 6) Much of the discussion regarding transportation banking service in this case surrounds the "Nicor Method" and its application to Ameren's transportation service. Staff witness Sackett explained in direct testimony that the Nicor Method goes beyond simply determining the maximum storage capacity that a transportation customer receives from Ameren via the tariff.

> …Additional provisions include a subscribable bank, peak day withdrawal rights linked to storage subscription, a cost recovery method using a charge per therm of storage capacity and a cost recovery mechanism for unsubscribed bank capacity….The Nicor Method integrates total storage capacity (seasonal storage) allocations and peak day deliverability based on proportional system characteristics. It also has a way to determine storage charges. It determines how to divide these three elements proportionally amongst customers. (Staff Ex. 13.0, p. 7)

The Nicor Method has three integrated features: subscribable peak day storage withdrawal rights, seasonal storage, and storage costs. These are based on the proportion of gas that can be delivered from storage on a design day, the most extreme temperature day that the utility plans for, and the expected use on that day of all customers, both sales and transportation. Transportation customers as a group are able to subscribe to peak day storage withdrawal rights up to the ratio of the sum of their total maximum daily contract quantities to the design day total usage. The seasonal storage for a customer is set to provide the same proportion of the total seasonal storage as the proportion of deliverability the customer receives from storage on a peak day. Storage costs are recovered through a charge on storage capacity. (Staff Ex. 13.0, p. 8)

The Nicor Method (as well as the Peoples Method) affords transportation customers the same rights to storage capacity and storage deliverability on a peak day as it grants sales customers.[63] The Commission has historically approved transportation programs that reflect this basic approach.[64] (Staff Ex. 29.0, pp. 3-4)

Ameren opposes the premise of proportional storage rights. Ameren has

[63] This is evident from the approach taken to determine peak day parameters, seasonal parameters, and storage cost allocation, all by using relative peak day for each calculation.
[64] See Final Orders in Docket Nos. 04-0779, p. 138 and 08-0363, p. 115.

historically opposed any banks for transportation customers. In 2007, Ameren proposed to eliminate the banks of its legacy transportation customers and to implement a transportation service devoid of banks. Ameren's basic view of transportation customers as second-class customers without any inherent rights to storage is evident from Ameren's continued resistance to equitable access to peak day deliverability and seasonal storage capacity. As will be discussed below, Ameren's proposal in this case may deprive some transportation customers of access to storage altogether.

Much of the discussion regarding the application of the Nicor Method to Ameren revolves around Ameren's ability to provide proportional rights of storage capacity and deliverability to transportation customers. In both of these areas, Ameren currently provides rights that are below the proportional level. The expansion of these rights would have an impact on sales customers. The question is whether such impacts are fair and appropriate given the current state of affairs. Ameren's portfolio is likely going to have to adjust under either the Companies' or Staff's proposal based on the amount of maximum storage capacity selected by transportation customers as a group.

Company witness Eggers charges that Staff has not established that Ameren's system is "operationally comparable" to that of Nicor Gas. (Ameren Ex. 34.0, p. 2) However, Ameren never defines this concept on the record nor proves that the two systems are sufficiently different as to make the Nicor method inappropriate for Ameren's systems. In surrebuttal, Ameren describes system differences that it believes distinguishes it from Nicor Gas. (Ameren Ex. 51.0, pp.7-8) However, some of these same differences exist between the three rate zones, yet Ameren has proposed uniform maximum storage capacity and uniform Critical Day ("CD") withdrawal rights across the rate zones.

Additionally, Mr. Eggers describes Staff's proposal to apply the Nicor Method to Ameren's system as a "one-size-fits-all" method. (Ameren Ex. 34.0, p. 2) This is not correct; Staff's proposal to apply the Nicor method to Ameren is "Ameren-specific." Under the Nicor Method, Ameren customers be given 15 days of bank, not the 31 that Nicor customers are given. Rather, the Nicor Method would allocate storage rights based on the assets in Ameren's own portfolio. The maximum storage capacity is Ameren's, not Nicor's; and the peak day withdrawal from storage is Ameren's, not Nicor's. (Staff Ex. 29.0, pp. 4-5)

Ameren proposes a uniform average bank level for all three rate zones even though the storage in those systems differ considerably. Under Ameren's original proposal, customers in Rate Zone 3, which historically has the most on-system storage allocated to it, could elect no bank while all the customers in Rate Zone 1 with the least on-system storage could elect up to 22 days. Even now, Ameren's surrebuttal position is that storage of up to 15 days for individual customers is available regardless of where on the system the customer is located, including customers on captive systems. (Ameren Ex. 51.0, pp23-24) Thus, Ameren's own proposal indicates that Ameren's system is more robust than it suggests by its "not operationally comparable" objections. (Staff Ex. 29.0, p. 5)

Several of Ameren's arguments ignore the gas operational concept of displacement. The American Gas Association ("AGA") defines displacement as, "Displacement transactions permit the lateral movement of gas through a transportation network. The configuration of many pipelines is such that it may not be apparent whether a given movement of gas is forward or backward from the point of receipt. It can be argued that all transportation service is performed by displacement as the physical delivery of the same molecules of gas is impossible." [65]

The first argument that Mr. Eggers makes reflects a willingness to ignore displacements and pertains to the treatment of specific gas in specific assets as belonging to a specific class of customers (i.e. sales or transportation customers). He claims that "[d]evoting [32]%[66] of the working capacity of a storage field to a customer group that may choose not to withdraw during the winter season therefore presents significant operational difficulties." (Ameren Ex. 34.0, p. 18) Mr. Eggers' statement implies that transportation customers "control" those assets.

Furthermore, his statement that on-system storage capacity is "devoted" to transportation customers directly contradicts an earlier statement that only sales gas goes into those fields. Mr. Eggers stated that Ameren currently fills on-system storage with sales customers' gas and puts transportation customers' gas in banks elsewhere within the system. This is just an accounting convention rather than a physical fact; that is, it relates to the accounting treatment of the gas in those banks but does not reflect the actual reality of the gas going into and coming out of Ameren's storage assets. (Tr., September 14, 2011, p. 497) He explained that, "[o]ur current storage resources permit this, as we physically fill on-system storage with sales customer gas and provide transportation customers the option to bank as they see fit within the 10 day 5.482 Bcf of BSL." (*Id.*, p. 17)

[65] http://www.aga.org/Kc/glossary/Pages/D.aspx, accessed on August 17, 2011.
[66] Given the corrections made in Staff Ex. 29.0, page 7 this amount should be 32%, rather than 47%. (See Tr., September 14, 2011, p. 510)

However, at the hearing, Mr. Eggers admitted that gas from transportation customers' injections into their banks does go into on-system storage. (Tr., September 14, 2011, p. 502) The gas going into those assets is a mixture of sales and transportation gas, and that given a reasonable injection target, those fields will not be harmed in any way by the transportation customers' actions. (Staff Ex. 29.0, p. 7)

The second argument that Mr. Eggers advances is that the amount of maximum storage capacity that Staff has proposed to allocate to transportation customers as a percentage of *on-system* assets is large enough that it would create "significant" operational issues for those assets. (Ameren Ex. 34.0, p. 18) However, since transportation customers do not really control gas in *on-system* assets, this is really not the issue. Ameren puts transportation customers' gas into its system and displacement takes care of it from there on.

In his direct testimony, Staff witness Sackett sets forth how the Nicor Method determines an individual transportation customer's peak day withdrawal rights. (Staff Ex.13.0, pp. 8-9) He then demonstrates how an individual customer's maximum storage capacity rights are calculated. (*Id*., pp. 9-10) Furthermore, Mr. Sackett explains that Nicor's linking of the two rights reflects their underlying physical relationship. He states, "The gas injected into storage both allows its withdrawal over the season and facilitates a maximum amount of gas to be withdrawn on a peak day by ensuring an adequate level of the pressure in the field." Staff Ex.13.0, pp. 11-12.

Mr. Sackett also demonstrates that under the Nicor Method, transportation customers are able to select the amount of storage capacity from any level from one times Maximum Daily Control Quantify ("MDCQ") to the maximum amount determined.

Customers are not able to select no bank, i.e., storage capacity. This subscribable feature enables transportation customers to choose the amount of storage that best suits their needs. (Staff Ex.13.0, p. 10)

Finally, Mr. Sackett explains that charges are based on the total cost of storage per unit of storage capacity. To determine the storage charges, the total cost of on-system storage is divided by the capacity of that storage. A transportation customer's charges for storage equal the customer's Bank Limit multiplied by the storage charge. (Staff Ex.13.0, pp. 10-11)[67]

Mr. Eggers also responded by claiming that such an expansion of rights would force Ameren to purchase additional storage capacity. He further objected that Staff's proposal grants transportation customers more deliverability from storage on a CD than on a non-critical day. (Ameren Ex. 34.0, p. 9-11) Staff witness Sackett responded to these arguments by pointing out that Ameren's current tariffs provide sales customers with a disproportionate peak day access to its storage assets. Correcting this distortion allows transportation customers their fair share of those assets while requiring them to pay proportionally for them. (Staff Ex. 29.0, p. 11)

Ameren can increase its peak day resources if necessary. Ameren originally proposed to eliminate at least one off-system storage asset from its portfolio.[68] Ameren has proposed to retain at least some of these assets because of Staff's proposal to make transportation custom equal rights to storage as sales customers. (Ameren Ex. 35.0, pp. 10) Since each asset has both maximum storage capacity and peak day deliverability

[67] Nicor has a separate rider, Rider 5 – Storage Service Cost Recovery, to recover the cost of unsubscribed bank capacity from sales customers. – (Attachment A to Staff Ex. 13.0)

components to it (Ameren Ex. 34.0, pp. 4-5), Ameren was planning on releasing both peak day deliverability and maximum storage capacity.

Of course, if Ameren did require more assets, sales customers would pay *less* than they currently do for on-system storage and *more* for off-system assets. The net effect of this is not known. (Staff Ex. 29.0, p. 11)

The Ameren Proposal

Ameren proposes to provide an unbundled storage bank for transportation customers under a new service called Rider TBS - Transportation Banking Service ("TBS"). Ameren proposes to only guarantee 10 days of bank to its customers as a group. Ameren witness Eggers opines that, because many transportation customers do not fully utilize their banks (i.e., they do not completely fill their banks), that it can offer, but not guarantee, individual customers more than 10 days. Ameren proposes an iterative process to reallocate capacity from transportation customers desiring less than ten days bank to those desiring more than ten days while ensuring that the demand for bank in aggregate does not exceed 10 days. (Ameren Ex. 14.0G, pp. 12-13)

Under Ameren's proposal, daily balanced customers (GDS-4 and GDS-5 customers that are large enough to be on GDS-4) can choose between 0 and 15[69] days, in whole day increments. Monthly balanced customers (GDS-2, GDS-3 and GDS-5 customers that are not large enough to be on GDS-4) can choose from between 5 and 15 days, in whole day increments. Mr. Eggers asserts that monthly balanced customers

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[68] Schedule F-8 b)3) shows a 32% reduction in off-system maximum storage capacity between the beginning in April 2012.

[69] The exact amount of this maximum was 22 in direct testimony (Ameren Ex. 14.0G, pp. 12-14) and rebuttal testimony. (Ameren Ex. 34.0G, p. 16-17) In surrebuttal testimony, Mr. Eggers stated that Ameren had accepted a maximum of up to 15 days for individual customers. However, he also stated that unsubscribed capacity would be given to customers desiring more than 15 day. (Ameren Ex. 51.0, pp23-24) Thus the exact maximum is unclear.

must, by definition, use storage assets to stay in balance, so they should be required to pay for at least 5 days. (Ameren Ex. 14.0G, pp. 12-14)

Ameren recommends that the restrictions on the ability to inject and withdraw gas from banks be maintained at the current levels; except that during the summer, customers are able to inject somewhat more gas than previously allowed. (Staff Ex.13.0, p. 14) Staff agrees with Ameren's proposal for Rider TBS including a subscribable bank and the increased injection rights during the summer, but, as outlined below, disagrees on the total size of that bank available to transportation customers.

Recommended changes to Rider TBS

Give transportation customers Critical Day withdrawal rights that are linked to the maximum storage capacity.

The current peak day withdrawal rights, which are independent of the bank capacity, were determined in the 2007 rate case (Order, Docket Nos. 07-0585 et. al., (Cons.), September 24, 2008, p. 313). They were originally proposed by Staff in response to Ameren's proposal to eliminate all bank and any associated peak day withdrawal rights. (See Staff Initial Brief, p. 304 and Staff Brief on Exceptions, pp. 107-110) Staff did not attempt to make the withdrawal rights proportional to Sales customers' withdrawal rights at that time. In the 2009 rate case, Ameren proposed to recover storage costs from all transportation customers based on the peak-day withdrawal rights of daily-balanced customers. Because Ameren did not propose to recover the costs for monthly-balanced customers based on their relatively liberal withdrawal rights, there was no need to correct this discrepancy until the present case. (Staff Ex.13.0, p. 18)

Under the Nicor Method, the system peak day deliverability is divided by the Peak Design Day, because if the Local Distribution Company ("LDC") is able to deliver a certain percentage of its Peak Design Day[70] from its on-system storage, then all the customer groups and individual customers should be able to deliver that same percentage from their portion of that storage. (Staff Ex.13.0, p. 16) Using the Nicor Method, Ameren's peak day deliverability of total on-system storage of 558,759 Dth should be divided by its on-system storage capacity of 25,765,200 Dth. This results in Critical Day withdrawal rights of 2.2% of the transportation customer's Bank Limit, which Staff recommends that the Commission approve in this case. (*Id.*, p. 18-19)

Give transportation customers proportional maximum storage capacity based on the Nicor Method.

Ameren proposes in Rider TBS to limit transportation customers as a group to what it calls the Banking Service Limit ("BSL"). Mr. Eggers defines the BSL as the MDCQ of all Rider T customers as of November 1, 2010, multiplied by 10, which is 5.48 Bcf. (Ameren Ex. 14.0G, p. 12) This level is *less* than the proportional level determined under the Nicor Method. (Staff Ex. 29.0, p. 19)

Staff supports the application of the Nicor Method to this aspect of operational parameters. This results in the allocation of 15 days of bank to transportation customers. (*Id.*, p. 16)

Mr. Eggers claims that Staff has not demonstrated that this peak day deliverability allocator is appropriate for dividing maximum storage capacity, because it is not operationally linked to that maximum storage capacity. Furthermore, he suggests other divisors might be more appropriate. He suggests that other possible divisors would be

[70] Nicor uses the term Peak Day Demand for this concept.

"actual usage on a peak day divided by total storage capacity," "the ratio of winter transportation customer throughput over total winter throughput," and "maximum coincident banked volumes of transportation customers in the winter(s) prior to the proceeding to gauge what they are actually using." (Ameren Ex. 34.0, p. 6)

However, Staff witness Sackett notes that none of these other divisors are operationally linked to maximum storage capacity, which supports the conclusion that there is no need to "operationally link" the numerator with the divisor. (Staff Ex. 29.0, p.14)

Peoples Gas and North Shore have both proposed to now use the same peak day allocator (peak day demand) in their current rate case (Docket Nos. 11-0281/0282 consolidated)(Cons.)) and that no one has opposed this allocator in that proceeding. (*Id.)*

In fact, Peoples Gas, North Shore, and Nicor have not indicated the need for an "operational link" for their allocator and have been able to operate their systems competently without this "link". (*Id*., p. 15)

Using relative peak day demand makes sense for two reasons. First, it is reasonable in this case because it is the only Commission-approved method for proportional capacity allocation. Second, Ameren uses relative peak day demand to allocate banks to individual transportation customers (as in days of bank times MDCQ). Since Ameren itself has used this method for allocating banks amongst transportation customers for decades, it is only logical to use this divisor to allocate proportional annual capacity. (*Id.*)

Consistent with the Nicor approach, Staff proposes that the BSL be set at 8.22 Bcf, which is equivalent to 15 days of bank. (*Id.*, p. 16) Additionally, Staff supports a single fall injection target, like the one used by Nicor, as appropriate for Ameren's transportation customers. This target should be set at the average maximum level that Ameren has filled its on-system storage for the past five years. (*Id.)*

Mr. Eggers indicates that if Ameren were to give proportional storage rights, this would require "some measure of cycling requirements." (Ameren Ex. 14.0G, p. 20) Cycling requirements are restrictions that force transportation customers to inject a certain amount of gas into storage during the summer injection season and/or to withdraw a certain amount of gas during the winter withdrawal season. The physical cycling of each field should not be confused with the cycling of the gas within the banks of transportation customers. Because of displacement, all gas can be cycled from the fields even if transportation customers do not withdraw it from their banks. One option to provide Ameren with a tool to handle the 15 day bank allocation to transportation customers is to implement a fall target in this docket. If this target is not effective, Ameren has the option of filing a 45-day filing or correcting it in the next rate case. (Staff Ex. 29.0, p. 16-17)

Even if the total storage capacity of individual customers or transportation customers as a group is limited by the Commission to Ameren's proposed BSL of 5.2 Bcf, the storage cost allocation and peak day rights determined under the Nicor Method are still relevant. The Nicor Method of tying the peak day withdrawal and total bank capacity level to a lower BSL is still appropriate. (*Id.*, p. 17)

In direct testimony, Staff witness Jones recommended changes to the language in the Company's proposed Rider TBS – Transportation Banking Service predicated on a Banking Service Limit ("BSL") that could change annually. The recommended changes included deleting the size of the BSL from the definition of the BSL and replacing the specific rates in Rider TBS with the formulas for calculating the rates approved by the Commission. (Staff Ex. 6.0, pp. 10-11) AIC clarified in Company witness Timothy Eggers revised direct testimony (Ameren Ex. 14.0G (Rev.), p. 14) and rebuttal testimony (Ameren Ex. 34.0, p. 30) that AIC's position is that the BSL will be fixed between rate proceedings. If the Transportation Banking Service approved by the Commission is structured such that the BSL and its attendant rates remain fixed between rate proceedings, Ms. Jones' recommended changes will not be necessary. However, if the Commission approves a Transportation Banking Service such that the BSL and its attendant rates would fluctuate between rate proceedings, Ms. Jones' recommended changes should also be approved. (Staff Ex. 23.0, pp. 3-4)

Charge transportation customers for storage costs based on the proportional Critical Day rights and maximum storage capacity.

To set rates for storage, Ameren proposes what it calls the Equitable Method,[71] which follows from one of the Federal Energy Regulatory Commission's ("FERC") approaches to rate-setting for storage services. This method charges 50% of fixed costs to total storage capacity and 50% to peak day delivery rights. This method provides an arbitrary weighting of storage costs between two interrelated functions, maximum storage capacity and peak day delivery rights. (Staff Ex.13.0, p. 15)

Mr. Eggers states that the "current cost allocation established in Ameren Illinois' previous rate cases is based on the percentage obtained by dividing 20% of the highest daily aggregate nomination of Rider T customers by the peak daily deliverability of Ameren Illinois' system storage fields." (Ameren Ex. 14.0G, p. 8) This method is not appropriate when the customer's maximum storage quantity varies based on the customer's choice.

[71] This is termed the Equitable method in reference to the Equitable Gas Company and is not a normative statement about its results. (Equitable Gas Company case, Docket No. CP85-876-000 (1986)).

Ameren's proposal for the cost recovery of underground storage costs is an attempt to relate the customer's storage charges to the amount of bank chosen. Ameren has proposed this method in order to address a shortcoming with the current method as noted above. However, the Nicor method proposed by Staff obviates the need for separate charges for the peak day delivery and maximum seasonal capacity as the two are tied and proportional to each other. (Staff Ex. 13.0, p. 22)

Ameren's method would allocate a significant portion of costs to the first day of bank. This results in two negative impacts. First, this is likely to drive at least some GDS-4 customers, who have the option, to select no bank in order to avoid the high initial bank charges. (*Id.)* Ameren has already stated that it does not expect electric generators to purchase banks at all because they seldom use the ones they currently have. (Ameren Ex. 14.0, p. 15) For these customers, the cost of that initial day of bank will likely be prohibitive. (Staff Ex. 29.0, p. 24)

The second concern is that Ameren's cost allocation proposal, when combined with Ameren's proposed requirement for monthly-balanced customers to subscribe to at least 5 days of bank, may drive some of these smaller customers back to sales service. Such a migration back to sales service would reduce the benefits now enjoyed under Transportation service. This migration would be based on the fact that transportation service is no longer economical. (Staff Ex. 13.0, pp. 22-23) Savings from being on transportation service depends on an individual customer's characteristics and circumstances. Ameren Ex. 34.1 confirms that Ameren's method allocates at least 50% of the costs to the first day of bank and, therefore, supports Staff's contention that, all other things being equal, if the amount of the additional storage cost allocated to the peak day component exceeds a customer's benefit from transportation service, then that customer will exercise the option to return to sales service. (Staff Ex. 29.0, p. 23)

Storage costs should reflect the *cost of services* and not the extra benefit received. While Ameren claims that it incurs higher costs in balancing monthly-balanced customers, it has not shown that this is the case. These monthly-balanced customers are smaller and less likely to place a strain on the system; their usage fluctuations are the same as when they were sales customers and Ameren internalized the fluctuations when they were sales customers. Staff believes that these imbalances should be viewed in much the same manner. (*Id.*, p. 25)

In the 2007 rate case, the Commission ordered Ameren to institute a system-wide monthly-balanced transportation service directed at smaller volume transportation customers. Since that time, transportation service to GDS-2 and GDS-3 customers has grown significantly from about 1100 to about 2100 currently. This growth reflects the appeal of this monthly-balanced program and its tariff parameters. The significant increase in the storage costs allocated to monthly-balanced customers may arbitrarily make transportation service uneconomical for smaller customers. (*Id.)*

Under its current tariff, Ameren uses a single charge that is based on deliverability, since maximum storage capacity is fixed. Now Ameren proposes to use two charges instead of a single charge that links deliverability and maximum storage capacity as is done by all of the other major gas utilities in this state. This charge has been used by Nicor Gas for more than a decade and has been proposed by Peoples Gas and North Shore in their present rate case. Ameren sees this Nicor Method charge as a charge per therm of maximum storage capacity. However, this single charge is equally a charge per therm of CD deliverability. Staff's proposal to use the Nicor Method, which recognizes the linkage between seasonal capacity and the ability to deliver a volume of gas on the peak day deliverability, links the two mathematically.(*Id.*, pp. 18-19)

Staff witness Sackett calculated this charge by dividing the on-system storage costs of $32,485,580 by the annual capacity of on-system storage of 25,765,200 Dth. This results in an annual per Dth of Bank Limit charge of $1.26, an annual per therm of Bank Limit charge of $0.126 and a monthly charge of $0.0105 per therm of Bank Limit. Doubling the proposed capacity charge and linking the Critical Day withdrawal right with the storage capacity eliminates the need for a separate capacity-based portion of that charge. (Staff Ex. 13.0, p. 23)

Because of the high percentage of storage costs allocated to the first day of bank under Ameren's proposal, if the Commission approves a dual charge for these storage costs, Staff recommends that the rights of monthly-balanced customers would need to be reduced to prevent them from being priced out of transportation service. (*Id.)*

Additionally, if the Commission approves a dual charge for these storage costs, Staff recommends that the charges for daily-balanced customers should be based on the Critical Day withdrawal rights which remain at 20% of DCN as opposed to the 20% of MDCQ that Ameren proposes. The Commission already decided that DCN is the appropriate parameter in the last rate case because that is the tariffed withdrawal rights. (*Id*.)

> While AIU's method attempts to consider bank withdrawals by transportation customers on a CD, when storage capacity is arguably the most important, the Commission is concerned that AIU has neglected to consider the big picture. By "big picture," the Commission is referring to AIU's existing tariff provisions which would deter transportation customers from making a reliability problem worse on a CD. Staff's method, on the other hand, appears to reflect the operational realities of a CD. The Commission finds

> Staff's approach to more reasonably reflect the withdrawal capacity of transportation customers on a peak day. Basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers. The more appropriate method is to allocate the on-system storage cost based on 20% of DCN, as suggested by Staff. Accordingly, AIU's gas COSS should reflect an allocation of on-system underground storage costs based on 20% of transportation customers' aggregate DCN on the 2008 peak day.
> (Final Order, Docket Nos. 09-0306 et al (Cons.), April 29, 2010, p. 257)

This case is the second rate case in a row in which Ameren has sought to charge daily-balanced transportation customers for more than their tariffed peak day withdrawal rights on a CD. If Ameren really wants to charge storage costs based on MDCQ, then it should rewrite its tariff to allow its daily-balanced customers to withdraw up to 20% of *MDCQ*. Instead, Ameren proposes to allocate *costs* based on *MDCQ* but to allocate Critical Day withdrawal *rights* based on *DCN*. The Company has provided no more convincing argument in this case than it did in the last and the Commission should reject their proposal again. (Staff Ex. 29.0, p. 20)

Mr. Eggers states that Ameren bases its proposal on the customers' rights (which he acknowledges are 20% of *DCN* for daily-balanced customers) which is what Staff has proposed be used.

> Ameren Illinois' proposed allocation, however, is designed to allocate on system storage costs to transportation customers *based on their daily rights to withdraw from their bank balances on a Critical Day*. Today those rights are *20% of DCN* for daily-balanced transportation customers and 50% of MDCQ for monthly balanced transportation customers.
>
> (Ameren Ex. 34.0, p. 24, emphasis added)

Ameren's own proposal, which is based on 20% of MDCQ, is *higher* than the tariff right cited above. So he rebuts Staff's proposal to use 20% of DCN by quoting the tariff which confirms that Staff's proposal, and not his, is the correct tariffed right. (Staff Ex. 29.0, p. 20

Ameren has provided the data from its historical peak days for the past 5 years. (*Id.*) The data shows that the average DCN for each historical peak is less than 43%. Staff witness Sackett asserts that this evidence "confirms that on noncritical historic peak days, transportation customers as a group have been nominating far less than their MDCQs and, thus, any attempt to allocate costs to them based on MDCQs will over allocate storage costs to them." (*Id.*, pp. 21-22)

If the Commission rejects Staff's proposal to link CD withdrawal rights, annual capacity and storage costs to the peak day through the MDCQ, then in lieu of such a tariff change, Staff recommends that the Commission allocate those costs based on 20% of the average historical peak DCN during the past two years – i.e. 43% of their MDCQ. Daily-balanced transportation customers historically had access to only 9% of MDCQ.[72] It would be appropriate to use this amount for the interim period for all transportation customers and, after Rider TBS becomes effective, for daily-balanced customers. (*Id.*, p. 22)

Additionally, Ameren's equitable method using the MDCQ should be rejected because it is internally inconsistent. Ameren has claimed that it plans for a peak day using the 20% of MDCQ number for daily-balanced customers.[73] Thus, Ameren plans for bank withdrawals at 20% of MDCQ, would charge those customers based on 20% of MDCQ,

[72] 43% of 20% of MDCQ equals 9%.
[73] By contrast, Ameren does not consider the usage of sales customers for whom there is an MDCQ in this same manner. Sales usage is considered in aggregate.

but only gives tariff rights at 20% of DCN, a number that Staff has shown is historically only 9% of MDCQ.[74]

Staff supports Ameren's proposal to require monthly-balanced customers to select at least five days of bank, but believes that this issue should be re-evaluated in the next rate case. (*Id.*, pp. 25-26)

Ameren plans for Rider TBS to go into effect on May 1, 2012. Prior to that date, the interim base rates that are to go into effect are not determined in the manner that the Commission ordered in Docket Nos. 09-0306 et al (Cons.). Mr. Eggers addresses interim rates in surrebuttal testimony and claims that Ameren applied the "equitable method" for that period using MDCQs instead of DCNs (and presumably a full 10 days of bank). (Ameren Ex. 51.0, p. 23)

Interim base rates should be determined in the manner that the Commission ordered in the previous rate case for those three months, i.e. allocate storage costs to all transportation customers based on 20% of DCN. In addition to the reasons stated above, Staff believes that this is also appropriate for those three months until the new rider TBS becomes effective because the tariff rights will not have changed and the Commission's current ruling is still appropriate. This ensures that there is no three month gap in which costs spike before more reasonable rates discussed here are implemented. Staff Ex. 29.0, p. 27. The charges should reflect the storage costs determined in this case but the method should remain fixed until Rider TBS becomes effective.

[74] Ameren admits that over estimating the peak day needs of transportation customers raise costs for the PGA. (Staff Group Cross Ex. 12-J, p. 1.)

Reject Ameren's changes to the Cashout provisions

Ameren proposes to change its Rider T cashouts so that Ameren will charge the Rider T customer the *higher* of the PGA price for the month in which the cashout occurs or the market price when the customer has inadequate deliveries and pay the customer the *lower* of the PGA price or the market price in month in which a cashout occurs. (Ameren 14.6G) Ameren has proposed an identical cashout in the new Rider TBS. (Ameren Ex. 14.4G) According to Mr. Eggers, these changes are necessary "to protect those [PGA] customers from any negative cost consequences of these cashouts[.]" (Ameren Ex. 14.0G, pp. 20-21)

Ameren made the same proposal in its 2007 rate case, Docket Nos. 07-0585 et. al., (Cons.). (See Staff Ex. 13, p. 27 citing Order, Docket Nos. 07-0585 et. al., (Cons.), September 24, 2008, p. 285)

Staff opposed Ameren's proposal in that 2007 rate case. (See Staff Ex. 13.0, p. 27) Ameren conceded that "arbitrage opportunities are *minimized* by Mr. Sackett's suggestion of having daily cashout pricing based upon daily market prices." (*Id.*)

Staff notes that Ameren has provided no evidence regarding the "negative cost consequences" to PGA customers *in net*. Further, the cashout provisions are already designed to deter transportation customer behavior that might impair the system. There is no evidence that the current provisions are inadequate. Finally, the Commission approved the current cashouts in Ameren's 2007 rate case, which do not include these specific provisions. (Staff Ex. 13.0, p. 28)

Mr. Eggers also argues that the PGA is more appropriate because it is the price paid by sales customers in that month for gas. He provides several exhibits that purportedly demonstrate the harm to sales customers from his alleged arbitrage. He also argues that Ameren's current cashout provisions encourage under-delivery. (Ameren Ex. 34.0, pp. 25-28)

Staff witness Sackett explains how diversity keeps the impact of transportation customers as a group minimal. In fact, transportation customer' imbalances may benefit Sales customers. Due to diversity, Ameren does not balance each customer individually each day. Rather, Ameren balances the entire system ; the imbalance of transportation customers may be off set by unplanned for imbalances of sales customers. Where transportation customers contribute to net imbalances, imbalances can be offset by market purchases for which the daily market price compensates the PGA for the gas purchased.. The daily market price, not the PGA is the appropriate price to use for transportation customer imbalances. Even if Ameren were not able to purchase at the end of the day these occurred, it could increase its purchases the next morning, which most likely would have an opening price very close to the closing price from the day prior. (Staff Ex. 29.0, pp. 29-30) Ameren concedes that it is able to purchase gas the next gas day once imbalances are noted and that the prices it faces that next day are generally close to the closing price from the day prior. (Staff Group Cross Ex. 12-L, p. 2)

Staff has also shown that since October 1, 2008, transportation customers have paid almost $600,000 annually in premiums to the Chicago Citygate Price ("CCP") by paying 10% more for gas outside the 20% deadband and receiving 10% less than the market price for gas delivered in excess of the 20% deadband. There is no evidence that the 33,289 therms daily average harms the system. Staff witness Sackett asserts that this tendency to under deliver will totally disappear if a CD is declared due to a $6 per therm penalty. And on any other day, it does not appear to be destabilizing to the system. (Staff

Ex. 29.0, p. 33) Ameren acknowledges that these under-deliveries do not destabilize the system. (Ameren Ex. 51.0, p. 22)

Ameren witness Eggers admits in surrebuttal testimony that this “It may be inconsequential when compared to a peak day volume,” but claims that it harms the sales customers economically. (Ameren Ex. 51.0, p. 22) However, the evidence provided by Mr. Eggers does not demonstrate that this is the case.

Furthermore, Ameren claimed that “… the cost for all gas on AIC’s system is the PGA price. There is no separate market priced gas waiting to handle cashout imbalances. (Ameren Ex. 51.0, p. 21) However, the Company admitted that there have been no actual purchases of any gas at the PGA rate. (Staff Group Cross Ex. 12-L, p. 1)

In addition, despite assurances that Ameren cannot buy gas at the daily price, Ameren witness Eggers acknowledged under cross-examination that Ameren makes daily gas purchases at its city gate at the Chicago Citygate Price. (Tr., September 14, 2011, p. 504) This is the exact same cashout price charged to daily-balanced customers. (Ameren Ex. 14.2, pp. 1, 6-8) Thus, the use of the PGA is not appropriate, and the current tariffed price is reasonable.

Finally, there are other market-based ways to address under-delivery rather than abandoning the market in favor of penal PGA cashouts. A reasonable alternative that would correct the under-deliveries would be to add a basis to the cashout price. (Staff Group Cross Ex. 12-N, p. 1) More reasonable measures such as this should be considered first. If the Commission is inclined to seek a corrective path to this under-delivery issue, it should encourage Ameren to work with Staff to find a less draconian means of addressing the issue through an appropriate tariff modification.

Recovery of Unsubscribed Bank Capacity Storage Costs

Ameren proposes to recover the costs associated with unsubscribed bank capacity from sales customers through a charge called the Unsubscribed Bank Capacity Charge ("UBCC") in Rider S. (Ameren Ex. 14.5G, p. 2). Ameren states that "a necessary element of the unbundled balancing service is an annual cost allocation to Rider T Customers of only the amount of bank capacity for which they subscribe." These costs should be borne by sales customers because they are "the beneficiaries of the unsubscribed bank capacity." (Ameren Ex. 14.0G, p. 16)

Staff witness Sackett agrees that a cost mechanism is necessary to support this level of bank flexibility for transportation customers. "Sales customers use and benefit from unsubscribed capacity, so it is reasonable that they should pay those costs." Also, the Commission has approved a similar mechanism in Nicor's Rider 5 – Storage Service Cost Recovery ("SSCR"). (Staff Ex. 13.0, p. 29)

Accordingly, Staff witness Sackett recommends that the Commission approve the UBCC. (Staff Ex. 29.0, p. 34)

If the Company's proposed addition of an Unsubscribed Bank Capacity Charge ("UBCC") to Rider S is allowed by the Commission, Staff witness Jones recommends that the formula to calculate the UBCC and language providing for an annual reconciliation be included in Rider S, as follows:

> Unsubscribed Bank Capacity Charge
>
> Effective on and after May 1, 2012, the cost of any unsubscribed bank capacity allocated to Rider TBS in the previous rate proceeding will be subject to monthly cost recovery from Rider S Customers on a per Therm basis. Such charge shall be based on the annual estimated Rider S Therms and shall be determined and filed at least once annually with the Commission as an informational filing. Such informational filing along with accompanying

supporting information shall be filed with the Commission no later than the 20th of the month preceding the effective date of the new Unsubscribed Bank Capacity Charge. Annually, this filing shall occur during April to become effective May 1. An informational filing with supporting information filed after the 20th of the month, but prior to the effective date, shall be accepted only if it corrects an error or errors from a timely filed informational filing for the same effective date.

The Unsubscribed Bank Capacity Charge shall be determined in accordance with the following formula:

UBCC = (A – (DR+MR) + RA) / T

Where:

UBCC = The Unsubscribed Bank Capacity Charge in Cents per Therm

A = The dollars allocated to Rider TBS in the most recent rate proceeding

DR = Projected revenues from Daily Balanced customer banking service charges for the 12-month period beginning May 1of the current year

MR = Projected revenues from Monthly Balanced customer banking service charges for the 12-month period beginning May 1of the current year

RA = The amount over/under recovered during the immediately preceding 12-month period ending April 30

T = The number of Therms of forecasted usage for the Rider S customers for the months remaining in the period from May 1 to April 30 in which the charge is to be applied.

The applicable Unsubscribed Bank Capacity Charge shall be included in the monthly PGA report submission and shall be applied along with other applicable Rider PGA and Rider S charges billed for service rendered during the Effective Month.

Annually, beginning in 2013, the Company shall provide a reconciliation to the Manager of Accounting by July 1 that compares UBCC revenue for the prior May through April recovery period with the costs that were to be recovered during the period. If the reconciliation adjustment results in a change of 0.01 cents per therm or greater to the current rate filed effective May 1, the Company shall make an informational filing by July 20th to set a new UBCC rate, effective August 1, for the remaining nine months of the current recovery period.

(Staff Ex. 6.0, pp. 12-14)

AIC agrees with Ms. Jones' recommendation. (Ameren Ex. 34.0, p. 31; Ameren Ex. 34.7, p. 2)

b. Rider T – Cashout Provisions

See above section for all discussion regarding Ameren's cashout proposal. All arguments made there apply here.

IX. PROPOSED SMALL VOLUME TRANSPORTATION PROGRAM

The RGS proposed that the Commission order AIC to begin a small-volume transportation ("SVT") program that would enable small volume residential and commercial customers to purchase their own gas supplies, rather than buying their commodity gas only from AIC. RGS also recommended that the SVT program include a Purchase of Receivables ("POR") for program suppliers and that a price-to-compare be calculated. (Staff Ex. 34.0, p. 2)

Staff recommends that the Commission not order an SVT program for Ameren in this rate case. (Staff Ex. 34.0, p. 2) Staff provided three reasons for its recommendation. First, RGS failed to show that customers are better off with a SVT program. Second, RGS did not offer details sufficient to enable such a program to be implemented. A general rate case like this docket does not allow for the comprehensive exchange of information needed to produce an entirely new service offering in AIC's tariff. Third, under the recently amended Section 5/19-130 of PUA, the Office of Retail Market Development ("ORMD") must compile a report that investigates the state of retail gas competition in Illinois, the barriers to development of competition and any other relevant information. (220 ILCS 5/19-130) In compiling this report, the ORMD must "gather input from all interested parties[.]" (*Id.*) The compilation of the ORMD report will provide an opportunity for alternative retail gas suppliers ("ARGS") to promote their ideas to improve retail gas markets to the Commission.

In Staff's view, the record in this proceeding does not support a finding regarding the benefits of a SVT program. The ORMD report will provide the Commission with an investigation of retail gas competition in Illinois. The Commission should consider the ORMD report when it decides upon the best way to promote the public interest rather than decide these issues in this case. The Commission will then have a more developed and comprehensive picture of the costs and benefits of a small volume gas transportation program, along with the characteristics that the program should have, than this rate case allows. (Staff Ex. 34.0, pp. 5-6)

X. OTHER

A. Rate Zone Schedules in Future Rate Filings

The Commission should note in its rate order for the instant docket the Company's acknowledgement of the continuing requirement pursuant to the Commission Order in Docket No. 10-0517 to provide schedules setting forth separate rate zone data with the initial filing of its future rate cases as long as separate rate zones pricing exists.

In Docket No. 10-0517, the Commission entered an order clarifying that AIC is required to provide separate rate base schedules, operating income schedules and embedded cost of service studies for each of the Company's separate rate zones with its future rate case filings as long as separate rate zone pricing exists. In his direct testimony, Staff witness Struck recommended that the Commission restate this continuing requirement in the Order in this case. (Staff Ex. 1.0, pp. 7-9)

In response, the Company acknowledged that it is under a continuing requirement to provide schedules setting forth separate rate zone data with the initial filing of its future rate cases as long as separate rate zone pricing exists. The Company noted that in Docket No. 10-0517, the Commission has already ordered AIC to provide such rate zone data. The Company indicated that it has complied with and fully intends to comply with the Commission Order in Docket No. 10-0517.

Therefore, Staff recommends the Commission include the following language in its Order in this proceeding:

> The Commission notes AIC's acknowledgment that AIC is required to provide separate rate base schedules, operating income schedules, and embedded cost of service studies for each of the separate rate zones with its rate case filings as long a separate rate zone pricing exists. The Commission further notes AIC's commitment to do so in future rate cases. (Ameren Ex. 21.0, p. 9)

B. Original Cost Determination

The Company requested that the Commission make a finding in the Order in this proceeding that AIC's plant balances as of December 31, 2009, reflected on Ameren Illinois Electric Schedule B-5 and Ameren Illinois Gas Schedule B-5, are approved for purposes of an original cost determination. (Ameren Ex. 2.0, p. 46) Staff witness Hathhorn agreed that a finding should be made using the December 31, 2009 plant balances; however, she testified that the determinations should be made separately by rate zones, and should also include certain adjustments in order to reflect prior Commission disallowance decisions and the Commission's final determination on the

NESC Adjustment. (Staff Ex. 2.0R, p. 16) She also accepted the Company's correction and agreed the final determinations should be based upon the amounts in Ameren Ex. 22.19. (Staff Ex. 20, p. 3) Therefore, the amounts that should be approved by rate zone are as reflected in Ameren Ex. 22.19, and the Commission's order in this case should include the following Findings and Ordering paragraphs:

> (x1) The Commission, based on AIC's electric Rate Zone I original cost of plant in service as of December 31, 2009, before adjustments, of $1,434,080,000, and reflecting the Commission's determination adjusting that figure, approves $1,432,782,000 as the original cost of plant for AIC's electric Rate Zone I as of said date;
>
> (x2) The Commission, based on AIC's electric Rate Zone II original cost of plant in service as of December 31, 2009, before adjustments, of $877,840,000, and reflecting the Commission's determination adjusting that figure, approves $875,318,000 as the original cost of plant for AIC's electric Rate Zone II as of said date;
>
> (x3) The Commission, based on AIC's electric Rate Zone III original cost of plant in service as of December 31, 2009, before adjustments, of $2,479,641,000, and reflecting the Commission's determination adjusting that figure, approves $2,475,858,000 as the original cost of plant for AIC's electric Rate Zone III as of said date;
>
> (x4) The Commission, based on AIC's gas Rate Zone I original cost of plant in service as of December 31, 2009, before adjustments, of $375,245,000, and reflecting the Commission's determination adjusting that figure, approves $374,930,000 as the original cost of plant for AIC's gas Rate Zone I as of said date;
>
> (x5) The Commission, based on AIC's gas Rate Zone II original cost of plant in service as of December 31, 2009, before adjustments, of $520,095,000, and reflecting the Commission's determination adjusting that figure, approves $519,714,000 as the original cost of plant for AIC's gas Rate Zone II as of said date; and
>
> (x6) The Commission, based on AIC's gas Rate Zone III original cost of plant in service as of December 31, 2009, before adjustments, of $954,029,000, and reflecting the Commission's determination adjusting that figure, approves $938,504,000 as the original cost of plant for AIC's gas Rate Zone III as of said date.

C. Depreciation Rate Study

Staff witness Mary H. Everson recommended that the Commission order AIC to prepare depreciation studies for each of the rate zones consistent with the rate zones established by the Commission in setting rates in this case and file the studies with the Commission within 6 months of the date of the order in this proceeding. The depreciation studies should be conducted prior to Ameren's next rate case. (Staff Ex. 5.0, p. 1)

In support of her recommendation, Ms. Everson stated that the last depreciation study proposed by AIC and approved by the Commission was provided in Docket Nos. 07-0585-07-0590(Cons.). Therefore, the current rates are based on outdated depreciation studies. (Staff Ex. 5.0, pp. 128-132)

In his rebuttal testimony, AIC witness Stafford agreed with Ms. Everson's proposal to conduct new depreciation studies. (AIC Ex. 22.0, p. 17) However, he indicated that Staff's recommended 6 month time frame was too short to complete the depreciation studies. (*Id*., p. 18) Mr. Stafford stated that in her response to AIC data request AIC-Staff 13.02, Ms. Everson agreed to modify the time period for providing the depreciation studies to 9 months instead of 6 months. (*Id*., pp. 18-19)

XI. CONCLUSION

WHEREFORE, for all of the following reasons, Staff respectfully requests that the

Commission's order in this proceeding reflect all of Staff's recommendations regarding the Company's request for a general increase in electric and gas rates.

October 11, 2011

Respectfully submitted,

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