STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	**07-0585**
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	**07-0586**
Proposed general increase in electric delivery service rates.	:	
	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	**07-0587**
Proposed general increase in electric delivery service rates.	:	
	:	
Central Illinois Light Company d/b/a AmerenCILCO	:	
	:	**07-0588**
Proposed general increase in gas delivery service rates.	:	
	:	
Central Illinois Public Service Company d/b/a AmerenCIPS	:	
	:	**07-0589**
Proposed general increase in gas delivery service rates.	:	
	:	
Illinois Power Company d/b/a AmerenIP	:	
	:	**07-0590**
Proposed general increase in gas delivery service rates.	:	**(Cons.)**

ORDER

DATED: September 24, 2008

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ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On November 2, 2007, Central Illinois Light Company d/b/a AmerenCILCO ("AmerenCILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS

("AmerenCIPS"), and Illinois Power Company d/b/a AmerenIP ("AmerenIP") each filed with the Illinois Commerce Commission (“Commission”) new and/or revised tariff sheets for electric and gas service. AmerenCILCO, AmerenCIPS, and AmerenIP are each a wholly owned subsidiary of Ameren Corporation ("Ameren") providing residential, commercial, and industrial electric and gas service throughout their respective service areas. AmerenCILCO, AmerenCIPS, and AmerenIP are collectively hereinafter referred to as Ameren Illinois Utilities ("AIU"). The new and revised tariff sheets ("Proposed Tariffs") proposed changes in electric and gas rates and the establishment of new riders, to be effective December 17, 2007. On December 5, 2007, the Commission entered six Suspension Orders suspending the Proposed Tariffs for each company to and including March 30, 2008 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. The Suspension Orders identify the specific tariff sheets filed by AIU. Upon suspension, AmerenCILCO's electric and gas filings became identified as Docket Nos. 07-0585 and 07-0588, respectively; AmerenCIPS' electric and gas filings became identified as Docket Nos. 07-0586 and 07-0589, respectively; and AmerenIP's electric and gas filings became identified as Docket Nos. 07-0587 and 07-0590, respectively. On March 12, 2008, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including September 30, 2008.

Notice of the filing of the proposed rate increases was posted in each of AIU‘s business offices and was published twice in newspapers of general circulation within each of AIU's service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, “Notice Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services.” In addition, AIU sent notice of the filing to its customers in a bill insert.

On December 4, 2007, AIU was notified of certain deficiencies in its filings in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). The deficiency letters required AIU to submit various missing information and provide explanations of certain portions of the rate filings. AIU provided information in response to the deficiency letters on January 4, 2008.

Petitions seeking leave to intervene were filed by the People of the State of Illinois through the Attorney General (“AG”), the Cities of Bloomington, Champaign, Decatur, Monticello, and Urbana and the Town of Normal (collectively referred to herein as the Local Government Interveners (“LGI”)), Citizens Utility Board (“CUB”), AARP,[1] System Council U-05 of the International Brotherhood of Electrical Workers, an association consisting of Local Unions 51, 309, 649, 702, and 1306 ("IBEW"), Grain and Feed Association of Illinois ("GFA"), Kroger Company ("Kroger"), Constellation NewEnergy-Gas Division, LLC ("CNE-Gas"), Constellation Energy Commodities Group, Inc., Vanguard Energy Services, LLC, and the Coalition of Energy Suppliers, which consists of Constellation NewEnergy, Inc., Direct Energy Services, LLC, Integrys

[1] In 1999, the "American Association of Retired Persons" changed its name to simply "AARP," in recognition of the fact that people do not have to be retired to be members.

Energy Services Corporation, and MidAmerican Energy Company. The University of Illinois, Air Products and Chemicals Company, ArcelorMittal Steel Company, Cargill, Inc., Caterpillar, Inc., Enbridge Energy, LLC, GBC Metals, LLC, Illinois Cement Company, PPG Industries, Inc., Tate and Lyle Ingredients Americas, Inc., and Viscofan USA, Inc. also intervened as members of the Illinois Industrial Energy Consumers (―IIEC”). The Commercial Group, an ad hoc association of retail companies that own and operate retail stores in the service areas of AIU intervened as well. For purposes of this proceeding, the Commercial Group consists of Best Buy Company, Inc., JC Penny Corporation, Inc., Macy's, Inc., and Wal-Mart Stores, Inc. All of the petitions to intervene were granted. Commission Staff ("Staff") participated as well.

On February 6, February 11, February 13, February 19, February 26, and February 28, 2008, a public forum was held in Marion, Decatur, Belleville, Peoria, Quincy, and Champaign, respectively, for the purpose of receiving public comment on the general increase in electric and gas rates proposed by AIU. These locations were selected because they represent some of the larger population centers in the AIU service areas. A transcript of each public forum was made and is available on the Commission's e-Docket system.

Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on January 3 and June 3, 2008. Thereafter, evidentiary hearings were held on June 9 through June 13, 2008. Following the Commission's ruling on a petition for interlocutory review, an additional evidentiary hearing was held on July 1, 2008. Appearances were entered by counsel on behalf of AIU, Staff, the AG, LGI, CUB, AARP, GFA, IIEC, Kroger, the Commercial Group, and CNE-Gas. The record was marked ―Heard and Taken” on August 11, 2008. Following the submission of AIU's response to a Post-Record Data Request by the Administrative Law Judges pursuant to Section 200.875 of 83 Ill. Adm. Code 200, "Rules of Practice," the record was reopened for the purpose of admitting said response and the Staff reply into the record. The record was again marked "Heard and Taken" on September 3, 2008.

At the evidentiary hearings, AIU called 33 witnesses to testify. The 33 witnesses include (1) Michael Adams, a Vice President with Concentric Energy Advisors, Inc. ("Concentric"),[2] (2) Mary Batcher, Tax National Director for Statistics and Sampling at Ernst & Young LLP, (3) Krista Bauer, Manager of Compensation and Performance for Ameren Services Company ("AMS"),[3] (4) Scott Cisel, Chief Executive Operating Officer of each AIU company, (5) Stephen Colyer, Director of Gas Operations for each AIU company, (6) Wilbon Cooper, a Manager of Rate Engineering and Analysis within AMS' Regulatory Policy and Planning Department, (7) Michael Getz, Managing Supervisor of

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[2] Concentric is a management consulting and economic advisory firm specializing in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses and negotiations.

[3] AMS is the service company subsidiary of Ameren and provides various services to its affiliates, including AIU.

Business Performance for AMS, (8) Scott Glaeser, Vice President of Gas Supply and System Control for the Gas Supply Division of AmerenEnergy Fuels and Services Company, (9) Philip Hanser, a principal in The Brattle Group, an economic consulting firm, (10) Laurie Karman, Managing Supervisor of Credit and Collections for AMS, (11) Leonard Jones, Managing Supervisor of Restructured Services within AMS' Regulatory Policy and Planning Department, (12) Charles Laderoute, President of the consulting firm Charles D. Laderoute, Ltd., (13) Mark Livasy, Superintendent of Energy Delivery Illinois for each AIU company, (14) Martin Lyons, Vice President and Controller of AMS and each AIU company, (15) Keith Martin, Manager of Customer Service and Energy Efficiency for each AIU company, (16) Kathleen McShane, President of the economic consulting firm Foster Associates, Inc., (17) Robert Mill, Director of AMS' Regulatory Policy and Planning Department, (18) Timothy Moloney, Managing Supervisor in AMS' Credit Risk Management Department, (19) Joseph Mullenschlader, Manager of Corporate Security for AMS, (20) Craig Nelson, Vice President of Regulatory Affairs and Financial Services of each AIU company, (21) Michael O'Bryan, Senior Capital Markets Specialist in Treasury-Corporate Finance of AMS, (22) Ronald Pate, Vice President of Regional Operations for each AIU company, (23) Robert Porter, Manager of Acquisitions for AMS, (24) Ronald Stafford, Managing Supervisor of Regulatory Accounting in AMS' Controller's Function, (25) Bruce Steinke, Vice President and Controller of Ameren, AMS, and each AIU company, (26) David Strawhun, a Career Engineer in Distribution System Planning for AMS, (27) John Taylor, a consultant with Concentric, (28) Stephen Underwood, Manger of Gas Storage for AMS, (29) William Warwick, Managing Supervisor of Rate Engineering within AMS' Regulatory Policy and Planning Department, (30) Gary Weiss, Manager of Regulatory Accounting for AMS, (31) Andrew Wichmann, a Financial Specialist in AMS' Controller's Function, (32) John Wiedmayer, a Project Manager of Depreciation Studies for Gannett Fleming, Inc.,[4] and (33) Robert Willen, Supervising Engineer of the Load Analysis Group within AMS' Corporate Planning Function.

Twelve witnesses testified on behalf of Staff. The Staff witnesses include (1) Theresa Ebrey, (2) Mary Everson, and (3) Daniel Kahle, Accountants in the Accounting Department of the Financial Analysis Division of the Commission's Bureau of Public Utilities, (4) Janis Freetly and (5) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, (6) Cheri Harden and (7) Peter Lazare, Rate Analysts in the Rates Department of the Financial Analysis Division, (8) Harry Stoller, Director of the Energy Division of the Bureau of Public Utilities, (9) Greg Rockrohr, a Senior Electrical Engineer in the Engineering Department of the Energy Division, (10) Eric Lounsberry, Supervisor of the Gas Section in the Engineering Department, (11) Dennis Anderson, a Senior Energy Engineer in the Gas Section, and (12) David Sackett, an Economic Analyst in the Policy Department of the Energy Division.

[4] Gannett Fleming, Inc. is a consulting firm that, among other things, assists clients prepare accounting and financial data for revenue requirement and cash working capital issues, allocate the cost of service among customer classes, and design customer rates.

IIEC offered five witnesses at the evidentiary hearings. IIEC's witnesses include Alan Chalfant, Michael Gorman, James Selecky, Robert Stephens, and David Stowe from the consulting firm of Brubaker & Associates, Inc.[5] David Effron, a consultant specializing in utility regulation, and Michael Brosch, a principal in the consulting firm Utilitech, Inc., testified on behalf of the AG and CUB. The AG also called Scott Rubin, an independent consultant and attorney specializing in matters affecting the public utility industry, to testify. Christopher Thomas, CUB's Director of Policy, Lynne Kiesling, a Senior Lecturer in the Department of Economics at Northwestern University, and Martin Cohen, an independent consultant specializing in regulatory policy analysis, testified on behalf of CUB. Kroger called Kevin Higgins, a principal at Energy Strategies, LLC,[6] to testify. Jeffrey Adkisson, GFA Executive Vice President and Treasurer, testified for GFA. Nancy Hughes, a principal and Senior Director with R.W. Beck, Inc.,[7] offered testimony for LGI. The Commercial Group called Richard Baudino, a consultant with the firm of J. Kennedy & Associates, Inc., to testify. James Germain, the Director of Customer Supply Management for CNE-Gas, and Lisa Rozumialski, a Manager of Gas Operations for CNE-Gas, both testified on behalf of CNE-Gas. Ralph Smith, a consultant with the accounting and regulatory consulting firm of Larkin & Associates, PLLC, testified for AARP. Paul Noble, Business Manager of IBEW Local 72 and Chairman of IBEW System Council U-05, testified on behalf of IBEW.

AIU, Staff, the AG, LGI, CUB, AARP, GFA, Kroger, CNE-Gas, the Commercial Group, and IIEC each filed an Initial Brief and Reply Brief. A Proposed Order was served on the parties. All but AARP filed a Brief on Exceptions. AIU, Staff, the AG, CUB, GFA, CNE-Gas, and IIEC each filed a Brief in Reply to Exceptions. The Briefs on Exceptions and Briefs in Reply to Exceptions have been considered in the preparation of this Order.

As a general matter, the Commission notes that in their respective Briefs on Exceptions, several parties complain that the Proposed Order did not specifically lay out each and every aspect of their argument and that in some instances the conclusion did not dispose of every aspect of, or basis underlying, each proposal. First, the Commission notes that, excluding the appendices, the proposed order is 360 pages in length and while not perfect, is generally adequate in summarizing parties' positions and arguments. Additionally, the Commission observes that Illinois courts have held that "The Commission is not required to make a finding on each evidentiary fact or claim; rather, it is sufficient that its findings are specific enough to permit an intelligent review of its decision." (<u>City of Chicago v. Illinois Commerce Commission and Commonwealth Edison Company</u>, 264 Ill. App. 3d 403, 409, 636 N.E.2d 709 (First District Appellate Court, 1993)) The Illinois Supreme Court further stated that "If the findings support the order, then the reviewing court examines the evidence to ascertain if the findings are supported by the facts." (<u>Brinker Trucking Co. v. Illinois Commerce Commission</u>, 19 Ill.

[5] Brubaker & Associates, Inc. offers consulting services in the energy, economic, and regulatory fields.
[6] Energy Strategies, LLC is a consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.
[7] R.W. Beck, Inc. offers consulting services in the areas of finance, energy, water/wastewater, and solid waste enterprises.

2d 354, 357, 166 N.E.2d 18, 20 (1960)) The Commission believes that in this lengthy and complicated Order it is not necessary to restate every aspect or basis for every argument either in the statement of a party's position or in the conclusion.

II. NATURE OF AIU'S OPERATIONS

Ameren formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIU covers roughly the lower two-thirds of Illinois. AmerenCILCO currently serves approximately 209,313 electric customers and 212,287 gas customers. Within AmerenCIPS' footprint are two rate areas: AmerenCIPS and AmerenCIPS Metro-East. AmerenCIPS currently serves approximately 387,097 electric customers and 185,484 gas customers. The AmerenCIPS Metro-East area is the former Illinois service area of Union Electric Company d/b/a AmerenUE ("AmerenUE"). This territory was transferred to AmerenCIPS in 2005. AmerenCIPS Metro-East serves approximately 18,000 customers in the Alton area. AmerenIP currently serves approximately 614,847 electric customers and 418,700 gas customers. All of AIU's operations are within Illinois, although an affiliate of AIU (AmerenUE) provides utility service in Missouri. Other affiliates of AIU provide unregulated services.

III. AIU'S PROPOSED TEST YEAR AND REVENUES

AIU proposes to use the 12 months ending December 31, 2006 as the test year in this proceeding. No party objects to the use of this test year. The Commission concludes that the historical test year AIU proposes is appropriate for purposes of this proceeding.

The Proposed Tariffs reflect an increase in delivery service revenues for all but the gas customers of AmerenCILCO. For AmerenCILCO gas customers, AIU proposes a decrease in revenues. The proposed changes in the delivery service operating revenues for each service type and territory are as follows:[8]

	ELECTRIC		GAS	
	Revenue Change	% Change	Revenue Change	% Change
AmerenCILCO	$10,151,000	8.22	-$3,851,310	-4.67
AmerenCIPS	$30,847,000	14.49	$14,396,496	22.11
AmerenIP	$139,320,000	39.12	$55,912,346	41.84

AIU determined these revenues using an 11.00% cost of equity. Since the proposed increase for AmerenIP electric customers is comparatively higher, for the first year that

[8] The numbers contained in the table reflect only proposed delivery service revenues since it is only those revenues at issue in this proceeding.

new rates are in effect, AIU proposes to limit the increase to an 8.5% increase in *bundled* rates for the residential customer class as a whole, based on current power supply costs.

AIU's last electric delivery service rate cases were consolidated Docket Nos. 06-0070, 06-0071, and 06-0072. AmerenCILCO's last gas rate case was Docket No. 02-0837. AmerenCIPS' last gas rate case was Docket No. 03-0008. AmerenIP's last gas rate case was Docket No. 04-0476.

IV. RATE BASE

A. Introduction

The rate base represents the net level of investment that a utility company has dedicated to public service on which it is entitled to earn a return. The rate base consists principally of book investment in utility plant and working capital, less deductions to reflect other sources of funds, such as deferred taxes. Schedules showing AIU's rate base for each utility at present and recommended rates for the test year ending December 31, 2006 were presented by AIU and Staff.

B. Resolved Issues

1. Accrued OPEB Adjustment

AG/CUB witness Effron recommends an adjustment to reflect Accrued Other Post Employment Benefits (-OPEB"). AIU agrees with this proposed adjustment. The Commission finds the AG/CUB proposed adjustment reasonable and appropriate and it is hereby adopted.

2. Written Procedures for Gas Losses

Staff recommends that AIU develop written procedures for the treatment of the source and types of losses from underground storage fields. AIU agrees to work with Staff to draft clear procedures regarding the accounting treatment of gas losses. The Commission finds Staff's recommendation to develop written procedures regarding the treatment of gas losses reasonable and directs AIU to collaborate with Staff to develop such written procedures that are agreeable to both AIU and Staff.

3. Electric Material and Supplies Inventory

Staff witness Everson proposes an adjustment to electric materials and supplies inventory for the percentage of accounts payable because accounts payable represents vendor-financing. AIU agrees with this adjustment. The Commission finds Staff's proposed adjustment to electric material and supplies inventory to be reasonable and it is hereby adopted.

4. Additional Cash Working Capital

Staff witness Kahle proposes an adjustment to eliminate AIU's proposed increase to rate base for additional cash working capital (“CWC”) for the electric operations related to a permanent increase in accounts receivable balances. AIU agrees to remove this proposed increase for each of the electric utilities. However, AIU, states that it reserves the right to raise this issue again in the future. The Commission finds the proposal to eliminate any increased accounts receivable balances related to electric operations reasonable and such increases should not be reflected in rate base in this proceeding.

5. Storm Recovery Costs

AIU initially proposed a pro forma adjustment to capture storm recovery costs that each of AIU's electric utilities incurred during 2006 and 2007. AIU‘s proposed pro forma adjustment utilized a five year amortization for these combined 2006 and 2007 storm recovery costs, and included each utility‘s unamortized storm recovery amounts in that utility‘s respective rate base. Staff witness Rockrohr recommends that the Commission reject AIU‘s proposed pro forma adjustment explaining that AIU‘s proposed rate treatment of storm recovery costs could provide a disincentive for the utility to bolster its distribution system to withstand storms. AIU agrees to modify its proposed treatment of storm recovery costs and use a six-year historical normalization period to calculate the storm recovery costs individually allowable for each of the AIU electric utilities. Mr. Rockrohr finds this alternative rate treatment of storm recovery costs described by AIU witness Stafford to be acceptable. The Commission finds AIU's amended proposal for the treatment of storm recovery costs reasonable and it is hereby adopted.

6. ADIT and Other Reserves

AG/CUB witness Effron recommends that Accumulated Deferred Income Taxes (“ADIT”) be adjusted to follow the treatment of the related reserves or accruals in the determination of rate base related to Pensions and Deferred Compensation. AIU agrees with these proposed adjustments. The Commission finds the AG/CUB's adjustment to ADIT related to Pension and Deferred Compensation reasonable and it is hereby adopted.

In its Brief on Exception, the AG recommends that the Proposed Order be modified to deduct the injuries and damages reserve from rate base, arguing that these are ratepayer-supplied funds. AIU disagrees with this proposal, noting that its modification of injuries and damages expense treatment in this case from an accrual basis to a cash basis for ratemaking, based on a five-year average of cash claims paid, is similar to the recommendation of Staff in these proceedings and to how such costs were established in Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.). AIU further states that the use of a cash basis eliminates the existence of a reserve balance for ratemaking, because there is no debit to expense and credit to a reserve account, or an advance payment to be recorded as an asset or as a negative reserve balance. In other words, a reserve balance, positive or negative, simply does not exist. It appears to the Commission that while a reserve balance still exists on the utilities' balance sheets, as the AG argues, it is only for reporting, not ratemaking, purposes. The Commission finds that the AG's proposed adjustment is not necessary for these reasons and rejects it.

7. Allocation for Common Plant for Substations

AIU allocates common facilities by primary function, in accordance with "The Illinois White Paper," adopted by the Commission in Docket No. 98-0894. While Staff witness Everson initially expressed concern with AIU's proposed allocation, she now agrees with AIU's allocation and does not propose any adjustment. The Commission finds the allocation previously decided by the Commission is appropriate and that approach is hereby adopted for purposes of allocating common plant for substations in this case.

C. Contested Issues

1. Plant Additions since Last Rate Case

a. AIU's Position

AIU states that, although it is in compliance with Commission document retention rules, certain aspects of its recordkeeping practices need to be improved to facilitate a timely and thorough review of plant additions. Moreover, AIU claims to have previously acknowledged that some of the documentation supporting plant additions was not provided to Staff as timely as it could have been. Having said this, AIU asserts that the requirement that parties engage in full and fair discovery and produce evidence in support of their position is not a one-way street.

AIU claims that despite repeated requests, Staff has never disclosed specifically which invoices were disallowed and for what reason. AIU argues that Staff's methodology for disallowing plant additions – that is, sampling a portion of additions and calculating a disallowance percentage that is applied to all additions – makes the failure to provide this information especially problematic. According to AIU, this is not a case where it has failed to document over $100 million of plant additions, as Staff's adjustment suggests. Disallowing a percentage of additions and applying that percentage to total plant additions, AIU avers, magnifies the impact of each disallowed invoice. Given that the ultimate dollar impact of each disallowed invoice is greater than any actual invoice amount, AIU claims identification of the specific invoices at issue is critical. AIU contends that Staff's failure to provide this information has prejudiced AIU. AIU argues that Staff's sampling methodology results in an overstatement of the proposed adjustment by about $111 million.

Identification of the invoices at issue, AIU claims, was accomplished through a process of elimination in which AIU "guessed" at the reason why Staff believes certain additions are allegedly unsupported. AIU says it provided documentation and explanation for every invoice that it believes Staff witness Everson disallowed. AIU states that Ameren Ex. 19.12 provides detailed information relating to approximately 1,300 invoices. Schedules 1 through 6 of the exhibit, AIU adds, list each invoice disallowed and explains why the disallowance is not appropriate. In some instances where AIU says it either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson, her adjustment was accepted. In surrebuttal, AIU compiled Ameren Ex. 43.6, which revised Ameren Ex. 19.12 and provided additional invoices and more supporting documentation and explanation. Ameren Exs. 19.13 and 61.1, AIU claims, provide similar supporting data for electronic transactions. According to AIU, all of these exhibits demonstrate that the amount of plant additions AIU seeks is adequately supported. AIU asserts that Staff dismisses all of the additional support and explanation provided in rebuttal and surrebuttal.

AIU asserts that Ms. Everson employs an invoice-by-invoice approach that is at odds with Staff's approach to analyzing plant additions in other rate cases. In other cases, AIU claims Staff often looks to continuing property records and other non-invoice documentation in order to identify additions that vary significantly in comparison to a utility's prior plant addition expenditures. AIU states that in contrast to Staff's typical review, in this case, Ms. Everson demanded that the AIU provide invoice level support for all selected expenditures. In AIU's view, this approach was burdensome, unwarranted, and unnecessary.

AIU says that among other things, Staff requested a list of all projects whose total costs were above $500,000, a total of 64 projects. AIU indicates that Staff requested invoices associated with 37 of these projects, of which Staff included 35 in its sample. AIU says it collected, by various queries on AIU's general ledger systems, details of the projects within Ms. Everson's request. This information was then used to compile a list of invoices, where each invoice was associated with a unique voucher number. AIU says these voucher numbers were then used to locate the hard copies of each invoice, which were then scanned and provided to Ms. Everson for review.

AIU says Ms. Everson conducted a review of invoices to determine what percentage of these invoices, for each of the utilities, was not supported by proper documentation. Ms. Everson states that she test sampled supporting documentation for third party vendors for capital additions. She cited seven issues or deficiencies with the cost substantiation provided by AIU: (1) duplicate invoices; (2) billings to the wrong company; (3) invoices not found that correspond to the listing of invoices provided; (4) amounts on invoices that did not correspond to the listing; (5) projects not determinable from the invoice or the invoice is not related to the project; (6) illegible invoices; and (7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. AIU states that Ms. Everson used her total of unsupported documentation to calculate the percentage of total project costs that is not supported. AIU says she then applied the percentage of additions for which AIU did not provide supporting documentation to the total of plant additions to calculate her adjustment to plant additions, reducing rate base by this amount. AIU complains that at no point has Ms. Everson identified specific invoices for which she recommends disallowance or the reason for the disallowance. In its Initial Brief, AIU also describes the efforts it made to obtain information it believed it needed to evaluate Ms. Everson's proposed disallowance.

According to AIU, the most important problem undermining Ms. Everson's analysis is her failure to identify which invoices she disallowed and why. In AIU's view, this limits the ability of AIU or the Commission to confirm or refute Ms. Everson's analysis. AIU states that although its' Data Requests 5.06, 5.07, and 5.08 requested specific information identifying each invoice disallowed and the reasons for each disallowance, Staff failed to provide this information. By failing to provide the specific reason for each denied invoice, AIU says it was forced to guess at the denial reason in its attempts to explain or refute her findings.

AIU says it recognizes that it bears the initial burden of proving the reasonableness and prudence of expenditures. AIU believes it has satisfied its burden of proving its plant additions, and argues that Staff has failed to meet its burden of proving its adjustment. AIU states that the burden of proof encompasses two concepts - the burden of persuasion and the burden of production. (AIU Initial Brief at 25, citing Consolidated Communications Consultant Services, Inc. v. Illinois Bell Telephone Company, Docket No. 99-0429) According to AIU, although the burden of persuasion – the ultimate burden of persuading the tribunal that the necessary elements of a claim have been proven – is assigned at the beginning of a dispute and does not shift during the course of the proceeding, the burden of producing evidence shifts between the parties as the case proceeds, depending on the nature of specific evidence and the issue it addresses. AIU asserts that in rate cases, once a utility makes a showing of the costs necessary to provide service under its proposed rates, it has established a prima facie case, and the burden then shifts to others to show that the costs incurred by the utility are unreasonable because of inefficiency or bad faith. (AIU Initial Brief at 25, citing City of Chicago v. Illinois Commerce Commission, 478 N.E.2d 1369, 1375, (Ill. Ct. App. 1985) ("City of Chicago")) AIU claims that where Staff proposes an adjustment, Staff bears the burden of producing evidence to support the reasonableness of the adjustment. AIU contends that burden is not met by pointing the finger back to the utility and arguing that the utility has not met its burden of proof. (AIU Initial Brief at 25, citing Commonwealth Edison Company ("ComEd"), Docket Nos. 83-0537/84-0555, Order at 183-84)

According to AIU, the Commission and courts recognize that the proponent of a position has the burden of supporting its position with credible, admissible evidence. AIU believes it produced evidence supporting its plant additions. Staff did not think the evidence was good enough. AIU says Staff is free to take that position, but it is ultimately the Commission, not Staff, that determines whether a party has met its burden of proof. AIU asserts that throughout this proceeding it put forth voluminous evidence supporting plant additions.

AIU argues that Staff failed to do anything sufficient to meet its burden with respect to its proposed adjustment. AIU says Staff never conducted an investigation of AIU's records at their offices. AIU suggests that had an on-site review occurred, any questions Ms. Everson had about AIU's documentation could have been answered. AIU complains that Ms. Everson never sent additional data requests seeking information in addition to or different from the information AIU provided in response to Staff Data Requests MHE 3.01-3.06. AIU complains that apart from correcting a few errors, Ms. Everson‘s adjustment did not change from her direct testimony, despite the massive amount of information produced by AIU in response to her concerns.

AIU says Ms. Everson did not rebut Dr. Batcher‘s comments regarding Ms. Everson‘s lack of documentation in her rebuttal testimony. According to AIU, Dr. Batcher testified that Ms. Everson did not provide any explanation of why she did not maintain detailed records of the review of sampled costs. AIU believes this is important because the sampled costs should be available to all parties to review and either agree or contest by arguments to the regulations, sound practice, or providing additional supporting or refuting evidence. In AIU's view, it is unfair to affected parties to deny them the ability to confirm or refute determinations made about individual sampled costs. AIU says that although it may be able to guess the reasons some of the invoices were rejected and provide counter arguments or additional supporting documents, that is a poor substitute for knowing why each invoice was rejected.

AIU witness Taylor states that sampling is the application of probability theory and statistics to gain knowledge about a population of concern, by the selection and review of individual observations within this population. Audit sampling, AIU avers, is the application of sampling techniques to the goals of an audit. AIU states that an ―audit” is defined as an analysis used to ascertain the validity or reliability of information. According to Statement of Auditing Standards (―SAS”) No. 39 (AU 350.01): ―Audit sampling is the application of an audit procedure to less than 100 percent of the items within an account balance or class of transactions for the purpose of evaluating some characteristics of the balance or class.” (AIU Initial Brief at 28, citing SAS No. 39, Auditing Sampling)

According to Dr. Batcher, given the importance of having a representative sample, planning regarding an audit sample is key. The first steps, AIU avers, are to learn about the population to be sampled, the type of estimates to be made from the sample, and the precision needed. Whether a statistical or judgment sample is used, AIU says the auditor approaches the testing of account balances with the recognition that some inconsistency in the sample details is to be expected, even though the account balances are fundamentally correct because of factors such as minor clerical errors, discounts, and irretrievable documentation. According to AIU, a materiality threshold is established as part of the sample planning process in recognition of these minor inconsistencies. For example, AIU suggests a materiality threshold of 1% might be established for invoices that can not be located on current systems. If testing is of older systems that are no longer used or, invoices have been archived, AIU suggests the threshold might be increased to something larger, like 5%, which in the auditor's judgment, makes allowance for the retrieval difficulties which do not, in and of themselves, indicate a problem with the invoice. AIU says other planning steps include consideration of the sample selection methodology, establishment of criteria for the review of selected invoices, determination of the format for documenting the individual decisions made for the selected invoices and the specific failure reason applied to each failed invoice, and the estimation, reporting, and documentation to be kept.

Dr. Batcher states that given the importance of having a representative sample, regulators often impose documentation standards. Dr. Batcher cites as examples, the Office of the Inspector General from the Department of Health and Human Services, and various state taxing authorities, as well as the Internal Revenue Service ("IRS"), which she says requires individual tracking of the results of the review of each sampled items, the estimators used, and various additional specific details.

It is Dr. Batcher's opinion that Staff has failed to provide the details of the careful planning typical of an audit sample acceptable for regulatory decisions. AIU says the sampling procedures were described as being based on judgment, knowledge of Commission rules, and experience, but the specific planning steps and documentation of the rationale for sample design decision were not provided. AIU complains that there is no rationale given for the choice of a judgmental rather than a statistical sample, no description of steps taken to assess the representative nature of the judgmental sample, no description of decision rules used in the evaluation of sampled costs, or of any of the other aspects of sample planning.

AIU argues that by only reviewing invoices associated with specific projects above $500,000 in total costs, Staff effectively divides the population into two populations, and selects a sample from only one of these populations. In AIU's view, this is no longer sampling the population of total plant additions, but sampling a population with total costs above $500,000. AIU says the remainder of costs associated with total plant additions (those costs outside of this population) was not sampled and is a distinct population.

Staff errs, AIU argues, by applying the characteristics of the sample it reviewed to a population that Staff did not review. AIU says there are two main types of plant additions: (1) Specific Projects – those projects whose total costs are above $100,000 and are related to a specific work order; and (2) Blanket Projects – reoccurring purchases or those projects whose total costs are below $100,000. Staff, AIU avers, did not review any invoices for specific projects whose total are less than $500,000, nor did Staff review any blanket projects. AIU argues that there is no reason to believe that the percentage of invoices associated with specific projects that Staff reviewed is representative of the percentage of invoices in all plant additions. AIU says, for instance, blanket projects include reoccurring purchases and installation costs of certain equipment, such as transformers. This population of costs, AIU suggests, may not include invoices, but rather receipts or other forms of recording an exchange, whereas specific projects are more often partially comprised of invoices.

Staff's rebuttal testimony, AIU claims, does not provide any evidence that the alleged substantiation error rate found in projects larger than $500,000 would be the same as the error rate in the smaller projects. According to AIU, Staff provides the unsupported statement that larger projects would be expected to have better documentation than smaller projects so, by inference, the alleged error rate would be a conservative estimate for the smaller projects. In fact, AIU says there are situations with carefully designed, unbiased statistical samples, in which Dr. Batcher has seen instances where larger projects or expenditures had higher error rates.

Staff's inclusion of electronic transactions as a portion of unsupported invoices, AIU asserts, is also improper. AIU says Staff's review is limited to invoices and does not include a review of supporting documentation related to electronic transactions. AIU believes it is unreasonable to determine a category of costs is fully unsupported simply because Staff fails to review support for that category of costs. AIU argues that this is synonymous to an auditor failing to review current inventory and concluding that such an inventory does not and has never existed.

According to AIU, Ms. Everson's statement that AIU offered no other sample is incorrect. AIU says that Mr. Taylor's rebuttal testimony and that of Dr. Batcher provides explanations of the proper population for which the sample's characteristics should be applied. AIU adds that Ameren Ex. 19.12 is a review of Staff's adjustment with the inclusion of all general ledger line items that Staff challenged. Within these exhibits, AIU claims it applied the review of these challenges to the proper population, calculated the amount still unsupported after review, and applied this percentage to the population from which the sample is derived. AIU asserts that this analysis is based on Staff's chosen sample, but provides a more complete and rigorous analysis of the sample and applies the sample's characteristics to the proper population.

AIU states that Mr. Taylor quantified the effect of Staff's improper application of its sample to total plant additions. AIU says Staff samples $35,446,676 out of $64,367,442, the population of projects with total costs over $500,000. AIU adds that the population that Staff does not sample from, those projects with total costs under $500,000 and blanket projects, totaled $547,845,558. AIU argues that incorrectly applying the sample's characteristics to the total plant additions results in a proposed disallowance of $124,622,861. AIU further argues that correctly applying the sample's characteristics to the population from which the sample is derived results in a proposed disallowance of $13,614,957. According to AIU, Staff's incorrect evaluation of the sample results in an overstatement of the proposed disallowance totaling $111,007,904.

AIU states that although Ms. Everson employs other audit methods that she could have used to validate and support capital additions as a whole, she errs by relying exclusively on her sample without also taking into consideration the results of her other audit reviews. AIU contends that Ms. Everson could have used continuing property records and property unit retirement records to review the AIU's plant additions;

however, a review of those records is not discussed anywhere in Ms. Everson's testimony.

Ms. Everson's analysis, AIU claims, is at odds with work done by other Staff witnesses in this case. AIU says Mr. Rockrohr samples the ten largest projects for each utility, and found issues with only two of those projects. One project related to plant held for future use, the other to a security system at an AmerenCIPS facility. AIU says the reasons for recommended disallowance of these projects relates to whether the investments were prudently incurred, not whether the project costs were sufficiently documented. According to AIU, Mr. Rockrohr's recommendation of only two disallowances is in contrast to Ms. Everson's conclusions in her direct testimony. AIU asserts that since Ms. Everson's approach applies to the entire universe of additions, she in effect is disallowing a second time some of the same capital additions dollars Mr. Rockrohr has proposed to disallow.

Ms. Everson's failure to take acquisitions, timing, and changes in accounting systems into account, AIU avers, leads to misleading and unfair results. AIU states that for AmerenCILCO's electric operations, 100% of the transactions reviewed occurred prior to 2005, prior to the acquisition of CILCO by Ameren. AIU adds that these projects were not transferred from Construction Work in Progress (―CWIP") to Utility Plant In Service until after 2004, and therefore are included in Ms. Everson's sample. AIU complains that Ms. Everson's sample results, however, were applied to 100% of all 2005 and 2006 capital additions placed in Utility Plant in Service. Since Ms. Everson has not considered how timing of transactions impacts her weighted disallowance calculations, AIU asserts that the application is flawed. AIU claims a more correct approach would attempt to differentiate the timing of transactions that give rise to 2005 to 2006 capital additions in a case such as this, where different accounting and invoice storage systems were employed with different owners, and the resulting application was applied to capital additions that for the most part, would have occurred after the transition periods. AIU says it is possible that pre-2005 transactions may be representative of post 2005 transactions, but Ms. Everson has not made that determination.

According to AIU, disallowing electronic transactions skews the percentage calculation of unsupported additions. AIU says all electronic transactions at issue occurred prior to October 2004 (acquisition of IP by Ameren) and yet the results were included in Ms. Everson's unsupported percentage for all additions. AIU says Ms. Everson's disallowance included 100% of all electronic transactions included within her sampled electric and gas projects. For gas projects, AIU indicates that those transactions totaled $2,286,148.32. AIU says Ms. Everson's unsupported percentage, with electronic transactions, is 51.74%. When this percent is applied to $118,215,000.00 of 2003-2006 capital additions, the resulting disallowance is $61,167,000.00 of capital additions. According to AIU, if Ms. Everson had adopted the same approach used by Staff in the prior IP electric rate case and excluded electronic transactions from her sample, the unsupported percentage would have changed to 9.62% from 51.74%, and resulted in a disallowance of $11,372,000.00. AIU asserts that Ms. Everson's inclusion of $2.286 million of electronic transactions in the denominator of her unsupported calculation resulted in a proposed disallowance of $50 million in capital additions. AIU also asserts that the application of Ms. Everson's unsupported percentage to any Commission authorized 2004 AmerenIP gas capital additions approved in Docket No. 04-0476 is a form of retroactive ratemaking, because the Commission has already approved inclusion of such additions in rates.

AIU believes Ms. Everson's exclusion of electronic transactions supporting AmerenIP expenditures is unfounded for other reasons as well. AIU states that Ameren Ex. 19.13 provides the detailed electronic transaction disallowed by Staff in its calculation of the disallowance for AmerenIP electric and gas plant additions since the last rate case. AIU contends that IP's electronic records are reliable and accurate representations of its costs. AIU says it explained in detail the process for creating and approving the invoices and how the invoices tie into the accounts payable system and that in the prior rate case, Staff did not propose to disallow any electronic transaction data.

AIU says that Ameren Ex. 61.1 contains its response and supplemental response to Staff Data Request 14.03, in which Staff requested the vendor invoices to support the amounts shown on Ameren Ex. 19.13 for plant additions. AIU asserts that Ameren Ex. 61.1 explains that, with respect to IP, vendor payment support for Ameren Ex. 19.13 is available in electronic format due to the electronic Contractor Invoicing system used by IP. AIU says that although information summarizing the electronic invoice records is already provided in Ameren Ex. 19.13, additional electronic information associated with vendor payments is available if desired. Thus, in response to Ms. Everson's concern in rebuttal that no actual invoices have been provided to support IP's plant additions, AIU claims Ameren Ex. 61.1 contains paper printouts of contractor invoice records that were electronically created and stored in IP's Contractor Invoicing system. AIU states that each electronic invoice contained in Ameren Ex. 61.1 shows all of the information necessary to substantiate project costs for specific plant additions for IP, such as contractor name, descriptions of the work, work order numbers, and the person approving the invoice for payment.

The methodology employed by Ms. Everson in this case, AIU asserts, is not consistent with Staff's approach in prior cases. AIU claims that while it is not suggesting that Staff is required to audit plant additions the same way in every case, the fact that the audit was performed differently in this case than in other cases demonstrates that other audit techniques were available to supplement Staff's review of plant additions in this case.

In Docket No. 07-0566 for ComEd, AIU asserts that Staff witness Griffin raised a number of issues with regard to ComEd capitalization policies and capital additions, and discussed changes to the ComEd Property Unit Catalog. AIU says Mr. Griffin did not propose a calculation of an unsupported percentage similar to that presented by Ms. Everson. According to AIU, there is no evidence of a similar review undertaken or discussed by Mr. Griffin or any other Staff witness in that rate case. It appears to AIU that Staff undertook no such sampling approach, and that Staff based its proposed capital additions adjustments entirely on other audit methods.

In recent cases involving other utilities, AIU avers that Staff has not required invoice-by-invoice support for plant additions. (AIU Initial Brief at 41, citing Docket Nos. 07-0241 and 07-0242 (Cons.) (Peoples Gas Light and Coke Company (“Peoples”)/North Shore Gas Company (“North Shore”)); Docket No. 04-0779 (Northern Illinois Gas Company (“Nicor”)); Docket No. 05-0597 (ComEd); Docket No. 06-0285 (Aqua Illinois, Inc. ("Aqua")); and Docket No. 07-0357 (Mt. Carmel Public Utility Company)) In these cases, AIU asserts that Staff‘s approach was different than Ms. Everson‘s approach in this case. AIU believes that in other cases, Staff has not required this level of detail in conducting its review, and the Commission has not required this level of detail in approving other utilities‘ plant additions.

AIU contends that in Illinois-American Water Company (“IAWC”) rate cases in Docket Nos. 90-0100, 92-0116, 95-0076, 97-0112, 00-0340, and 02-0690, Staff conducted an audit of capital additions, and one of the primary methods Staff relied on in those proceedings was a review of continuing property records, similar to that conducted by Ms. Everson in these proceedings. AIU says that in those cases where that audit method was employed, no further audit procedure was employed. According to AIU, Staff‘s approach in this case is not only flawed, it is an unwarranted departure from prior rate cases.

Ms. Everson, AIU states, admits that there may be valid reasons why certain invoice amounts do not match amounts on the list of projects that were provided. AIU claims that Ameren Exs. 19.12 and 43.6 demonstrate that there are valid explanations for many of the perceived discrepancies between the invoices and the listing, which casts doubt on Ms. Everson‘s proposed adjustment. AIU states that certain invoices differed by 1% from the amount presented in the project listing provided to Staff due to a discount extended by the vendor. AIU claims that the evidence it submitted in rebuttal supported the underlying cost directly in response to Ms. Everson‘s preferred audit approach of reviewing invoices. Where invoices could not be located or another reason was identified but could not be explained within the rebuttal filing deadline, AIU asserts that such costs are supported through other audit approaches, including support provided by the underlying general ledger queries, other project requirements, and continuing property records. According to AIU, Staff has not disputed that any of the underlying costs proposed for disallowance on Ms. Everson‘s Schedule 2.03 were either not incurred or should otherwise be ineligible for recovery, if the specific reason cited by Staff could be adequately addressed. AIU believes that any adjustments beyond those AIU conceded in rebuttal or in surrebuttal are inappropriate.

AIU states that with respect to Ms. Everson‘s first six criteria, Ameren Ex. 19.12, Schedules 1 through 6, Ms. Everson lists each invoice disallowed, based on a process of elimination, and a “best guess” as to the reason for the disallowance. According to AIU, Ameren Ex. 19.12, Schedules 1 through 6 also explain why the disallowance is not appropriate to the extent the explanation is unique or specific to that particular invoice.

AIU adds that Ameren Ex. 43.6, submitted in surrebuttal, updated Ameren Ex. 19.12 and provided more support. For some invoices, AIU says none of the reasons seemed to apply. In those cases, AIU indicated —No Reason” because the invoice was tied to the listing and none of the six criteria could be applied as a rationale for a disallowance. AIU states that there are some instances where AIU either could not locate an invoice or amounts did not match with the list relied on by Ms. Everson. While there are other ways to substantiate these costs, and some of the missing documents can directly be attributed to ownership transaction, AIU says it accepted, for purposes of this rate proceeding, an adjustment to rate base and depreciation expenses. AIU indicates that Ameren Ex. 19.12, Schedules 1 through 6 include a corrected calculation of Staff‘s Schedule 2.03 to consider evidence presented in rebuttal and an application of the unsupported percentage to the correct population, as discussed in the rebuttal testimonies of Mr. Taylor and Dr. Batcher.

AIU claims that Staff fails to adequately explain why Ms. Everson could not have used other audit methods to verify plant additions where an invoice was lacking. According to AIU, an invoice is one form of evidence that can be used to support plant addition amounts on the general ledger, but it is not the Holy Grail. In AIU's view, invoices are not the only appropriate, or even the best, evidence of plant addition costs. (AIU Reply Brief at 14, citing, <u>Preston Utilities Corporation v. ICC</u>, 39 Ill. 2d 457, 460 (1968) (upholding a Commission finding based on the premise that —the best evidence” of plant costs are —the general ledger, journal entries, and income tax returns”)) AIU says it provided additional supporting documentation in the form of continuing property records, property/retirement unit catalogs, accounts payable records, the contractor system, and vendors‘ verifications. According to AIU, Staff‘s position is that none of this is a substitute for an invoice. AIU says, according to Staff, if there is no invoice for a project then the costs can not be supported. According to AIU, Staff has, in other cases, relied exclusively on continuing property records, property retirement catalogs, and other forms of non-invoice support to justify plant additions.

AIU alleges that Ms. Everson‘s rebuttal testimony does not respond to a large portion of Mr. Stafford‘s rebuttal testimony. AIU asserts that the vast majority of the invoices detail explanations Mr. Stafford provided in rebuttal, with the exception of a few specific examples. AIU claims Ms. Everson does not address why she continues to disallow costs where the exact amount of the cost was highlighted on the invoice. AIU contends there are at least 265 invoices totaling about $1.7 million, with no explanation as to why these costs remain unsupported.

AIU argues that Staff‘s failure to review information provided to support plant additions cast serious doubt on the validity of Ms. Everson‘s adjustment. AIU asserts that before Ms. Everson filed her rebuttal testimony, AIU supplemented its responses to Ms. Everson‘s Data Requests MHE 3.03 and 3.06. AIU claims its supplemental responses modified the amount attributable to electronic transactions. AIU says Ms. Everson refused to incorporate this supplemental information into her analysis.

AIU claims to have been and currently be in compliance with the Commission's document retention requirements. AIU asserts that it has appropriate document systems and controls in place, and has made significant enhancements to its systems and controls. AIU says that Ameren Ex. 52.1 is a detailed description of its project file maintenance procedures. According to AIU, these procedures indicate that it has a proper system for retaining documents in place.

Even if the Commission were to find that AIU is or was not in compliance with Commission rules, taking into consideration that the data and records at issue are largely pre-acquisition, AIU believes this finding would not justify permanent disallowance. Permanent disallowance, AIU argues, is the rate case equivalent of the death penalty. Where rate base items are permanently disallowed, AIU says the utility may never earn a return on or of those items. Permanent disallowance, AIU claims, is therefore reserved for imprudent expenditures. AIU says its research reveals no precedent for permanent disallowance of prudent expenditures based on allegedly deficient documentation. No party to this proceeding, AIU adds, has alleged that any amounts included in Ms. Everson's adjustment represent imprudent expenditures. According to AIU, Staff has offered no support for its assertion that a permanent disallowance can be ordered based on documentation concerns. Because there is no issue in this proceeding concerning the prudence of any expenditures for plant additions, AIU maintains there is no basis in law or fact to permanently disallow rate base recovery of any such additions.

If the Commission feels that AIU has not adequately supported plant additions, AIU says it is prepared to suffer the consequences. While it would be one thing to disallow plant additions in this case, AIU asserts that to permanently disallow any plant additions is entirely different. AIU says it would be forever precluded from earning a return on or of property used and useful in providing service. AIU expresses concern that it would send a message that AIU loses not only in this case, but in all future cases. If any plant additions are disallowed in this case, AIU argues that those additions under the law must be included in rate base in the next case, provided they are adequately supported at that time. (AIU Initial Brief at 47, citing Illinois Power Co., Docket No. 89-0276, Order at 315 (1990))

AIU states that Staff cites no case law or Commission decision to support a permanent disallowance. AIU says it does not dispute that CILCO and IP were public utilities and subject to the Commission's record retention rules. According to AIU, left unsaid by Staff is what current AIU management was supposed to do to ensure that CILCO and IP properly maintained records before Ameren acquired those entities. AIU states that to the extent any violations occurred prior to Ameren's acquisitions, they were committed by the prior owners.

In AIU's view, Staff's recommendation for a fine should also be rejected. AIU claims Staff has ignored evidence provided by AIU that responds to many of Staff's concerns regarding plant records. AIU asserts that most of the difficulties in locating records arose from the fact that two of the utilities were previously under different ownership. While it may be true that these companies had record keeping obligations before being acquired by Ameren, AIU claims it is equally true that Ameren had absolutely nothing to do with these companies' recordkeeping practices until it acquired the companies. AIU says that Ameren acquired AmerenCILCO in early 2003 and AmerenIP at the end of 2004. While this proceeding deals with projects that went into service by the end of a 2006 test year, AIU asserts that many of those projects included costs, and related invoices, that predated Ameren's acquisitions.

In addition to AIU's lack of control over prior record preservation, AIU says there were also transitional issues, such as IP's use of a particular electronic document system that was taken out of service when AmerenIP was integrated into the Ameren system. With respect to AmerenCILCO, before the acquisition by Ameren, AIU claims there were two different systems in place. Prior to the acquisition of CILCO by AES in late 1998, AIU says invoices were centrally processed by a corporate Accounts Payable department. This is consistent with the system utilized by AIU. Starting in 1999 under AES' ownership, in addition to a small centralized accounts payable group that processed electronic payments and miscellaneous invoices, AIU says decentralized accounts payable processes were set up at the Duck Creek, Edwards, Springfield, Persimmon Gas, and Pioneer Park Electric areas. AIU states that each area received its own invoices and had separate checking accounts to pay vendors. AIU adds that all five areas were also responsible for bank reconciliations as well as retaining and storing their checks, bank statements, and invoices. According to AIU, the invoices at Pioneer Park Electric were housed in boxes in the storeroom and erroneously discarded after the acquisition by Ameren. AIU indicates it is not aware of any systemic loss of AmerenCILCO invoices other than those destroyed at Pioneer Park Electric. AIU states that for AmerenCILCO, 100% of the transactions sampled by Ms. Everson occurred prior to the acquisition of CILCO by Ameren.

Although AIU believes the Commission should reject the recommendations for fines and permanent disallowance, AIU says it has no objection to a requirement that it subject its document processing and retention for plant additions and retirements to an internal audit. AIU says that Ameren's internal audit department already reviews these matters annually, and works with its outside auditors to review document processing and retention. AIU indicates that Ameren Ex. 52.2 is a detailed outline of the most recent review. In addition, AIU says that it has already asked internal audit to review the issues surrounding the CILCO pre-acquisition document loss and make any appropriate recommendations.

AIU further claims that Staff's call for penalties fails to recognize that AIU is already being penalized. AIU states that all of the assets have already been in service since 2006 or earlier, and it will not earn a return on such assets until at least October 2008. In light of this fact, AIU contends that permanent disallowance and/or fines would be excessive, confiscatory, and unwarranted. In response to Staff's claims that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these additions, AIU suggests that Staff review the information already provided in Ameren Exs. 19.12 and 43.6. AIU insists that the information supporting plant additions is available today.

In response to Staff's suggestion that permanent disallowance is warranted to provide AIU with the incentive to adequately support plant additions and to make AIU accept responsibility, AIU says it has done nothing wrong. AIU suggests that to the extent the Commission believes otherwise, the remedy is to disallow certain plant additions in this case. AIU claims it would have an incentive to document plant additions in a manner acceptable to the Commission in the next case in order to recover the costs of those additions. AIU maintains that if it provides support for these additions in the next case, it is legally entitled to recover the costs, regardless of the outcome in this case.

In response to Staff's assertion that AIU's records are in remarkably poor condition, AIU alleges that Ms. Everson is in no position to make such a claim. AIU says she did not perform her review at AIU's offices and does not otherwise have any basis to pass judgment on how AIU keep its records. AIU states that her assessment is based solely on what AIU provided to her during discovery in this proceeding. According to AIU, Staff is free to criticize the format in which information was provided in discovery, but there is no record support for the statement that the manner in which information was produced in discovery is reflective of how records are compiled and maintained at AIU's offices.

In AIU's view, Staff overplays the effort needed to review the information provided by AIU. The volume of information involved, AIU claims, is a direct reflection of the scope of Staff's adjustment. According to AIU, whether Staff has thoroughly reviewed it or not, this evidence should not be ignored.

AIU contends that Staff attempts to reverse the burden of proof. In AIU's view, Staff's arguments and position in this case seem to ignore the fact that invoices offer additional support for general ledger amounts – not the other way around. AIU says its books are regulated, and audited, and are evidence in and of themselves of AIU's costs. According to AIU, Staff has ignored the significance of AIU's audited records, the controls that are in place, and the existence of the plant additions themselves. AIU complains that Staff's proposed adjustments would effectively disallow from rate base approximately $150 million in plant additions while AIU believes the correct adjustment is approximately $25.6 million.

AIU disputes Staff's claim that providing Ex. 19.12 during rebuttal constitutes a deliberate attempt to withhold information. AIU asserts that this information was provided in direct response to Staff's direct testimony recommending the disallowances. AIU says it had no motive to withhold information that supports plant additions. AIU argues that considering the experience in prior cases, AIU had every reason to be as above-board with Staff as possible in this case.

In response to Staff's complaints about receiving information after Staff's rebuttal, AIU claims that is the point of surrebuttal. In AIU's view, there is nothing improper about providing surrebuttal evidence that is responsive to Staff's rebuttal testimony. AIU says the surrebuttal evidence was put forth specifically to rebut the positions taken by Staff in its rebuttal.

Staff suggests that its original proposed adjustments should be adopted unless the decision maker conducts an analysis of the information provided in Ameren's surrebuttal testimony. AIU says it agrees that the Commission should analyze its surrebuttal evidence. According to AIU, the fact that it may be time consuming and meticulous to review the data is not a reason to ignore it. AIU claims it would not be nearly as time consuming and meticulous to review AIU's evidence as Staff would like the Commission to believe.

AIU says with regard to Ameren Ex. 43.6, Staff basically suggests that the information in this exhibit should be ignored because it is too hard to figure out. AIU agrees that this exhibit is hard to figure out if reviewed in the manner that Staff suggests and as described in Staff's Initial Brief. AIU states that Ex. 43.6 updates, corrects, and supplements Ameren Ex. 19.12. AIU alleges that Staff's apparent objective is not to determine whether Ex. 43.6 supports the requested level of plant additions, but whether the information provided as new information in surrebuttal was not in fact duplicative of earlier productions. AIU claims that Staff spent an afternoon cross-examining Mr. Stafford about discrepancies as low as $2.55 and $2.32. According to AIU, approximately 98% of the evidence was in Staff's hands after AIU submitted its rebuttal testimony. AIU asserts that even if Ameren Ex. 43.6 is not considered, Ameren Ex. 19.12 largely stands on its own in support of the requested level of plant additions.

Staff argues that the Commission should disregard the vendor supplied invoices contained in Ameren Ex. 42.2. First, AIU says Staff argues that some of the invoices contain amounts that do not agree with the summary listing. AIU claims that AIU witness Nelson explains why the amounts are different. Second, AIU says Staff complains that the affidavits are hearsay. AIU responds that they are part of the record. Third, AIU says Staff does not like how some of the invoices are worded. AIU asserts that regardless of how they are worded, the affidavits support the amount of AIU's plant additions.

According to AIU, Staff also attempts to create an issue from the fact that certain invoices were mistakenly billed to the wrong AIU entity by contractors. AIU suggests that the Commission understands that each of the utilities is a separate legal entity with separate books and records. AIU claims the significance of this legal separation is not always apparent to contractors that perform work for AIU. AIU states that its project managers make sure that invoices are assigned to the proper utility and project. In AIU's view, that this explanation is not apparent from the face of an actual invoice is of no import. That, AIU argues, is the reason why the project manager follows up to make sure the proper company is charged.

AIU understands Staff's position to be that if Staff could not read an invoice, the amount supported is $0. AIU suggests that Staff could have advised it that there were certain invoices that were illegible, but Staff never did so. AIU claims that had Ms. Everson promptly made known that she could not read some of the invoices, AIU would have quickly provided better copies. AIU says when this issue was made known to it, Mr. Stafford provided legible copies.

AIU states that where invoices did not match the summary listings, Staff proposes to disallow the entire invoice amount. AIU maintains that there could be legitimate reasons for the differences. This being the case, AIU believes it is not unreasonable to expect Staff to make some effort to determine whether such a legitimate reason exists. AIU suggests a good place to start would be to identify to AIU which invoice amounts do not match the summary listing. AIU says Staff never did so, claiming it has no obligation to further expend its limited resources to help AIU satisfy its burden of proof. AIU insists that Staff has the burden to produce evidence to support its adjustments. AIU says it provided responsive evidence that proves, despite differences between invoice amounts and amounts on the summary listing, the reasonableness of the addition.

AIU also claims that many of the differences are a few dollars. AIU states that Voucher #003347 associated with AmerenCIPS project 16895 is an invoice for $391.08. AIU believes that Ms. Everson disallowed this invoice because the amount presented on the summary was $387.17. AIU claims the difference is attributable to a 1% discount for early payment.

In response to Staff's assertion that AIU never provided evidence to substantiate its purchasing rate policy, AIU claims it produced detailed schedules identifying each discrepancy attributable to a purchasing rate. (Ameren Exs. 19.12 and 43.6) In addition, AIU says it responded to Staff Data Request 12.05 by providing a copy of AmerenCIPS purchasing rate policy in effect during June 2004. AIU complains that Staff did not issue any further Data Requests to better understand how AIU's purchasing rates worked. AIU further complains that unlike the prior rate case, in which Staff had discussions with AIU regarding purchase rates to obtain a better understanding of how such rates worked, Staff made no such effort to understand purchase rates in this case.

With regard to invoices that included finance charges, AIU complains that Staff attempts to make a mountain out of a mole hill. AIU says there is no list of which invoices included finance charges. Ms. Everson agrees that it is reasonable to ensure that an invoice amount is appropriate before paying the invoice. AIU states that if being reasonable ultimately results in the imposition of finance charges, so be it. AIU notes that where invoice amounts differed because of the application of a discount for early payment, Ms. Everson excluded the entire invoice because of the perceived discrepancy.

AIU asserts that it learned for the first time, through Staff's Initial Brief, that employee meals are another category of expense items that Staff disallowed. According to AIU, Staff relies on the fact that, while on the stand, Mr. Stafford could not cite a definitive reference from the Uniform System of Accounts ("USOA") indicating that employee meals may be capitalized as part of plant additions. According to AIU, the USOA does support the capitalization of employee meals. Specifically, Electric Plant Instruction 3, under —Components of Construction Costs," establishes that —Labor includes the pay and expenses of employees of the utility engaged on construction work." (18 CFR § 101 (emphasis added); 83 Ill. Admin 415.430.)

AIU says Staff's position on electronic transfers is based on its review of Ameren Ex. 19.13, which provides in spreadsheet form a description of electronic transactions. AIU states that contrary to Staff's assertion that this information came from the general ledger, Ex. 19.13 came from a separate system that contains information above and beyond the information contained in the general ledger. AIU complains that Staff fails to mention that AIU witness Livasy submits Ameren Ex. 61.1, which provides printed copies of invoice records maintained in AmerenIP's electronic transaction records. AIU says it is true that AIU believed that these records could not be retrieved from a legacy system; however, the records have since been retrieved. AIU claims the records should not be ignored. AIU further claims that all of the information necessary to support the electronic transactions, which total approximately $1.5 million, is contained in Ameren Ex. 61.1.

With respect to the 2004 IP gas historical plant additions, Staff claims that despite the fact that IP was allowed a certain level of 2004 pro forma plant additions in the last rate case, it is appropriate to disallow 2004 plant additions in this case. AIU believes Staff's arguments are misguided because some of the costs approved by the Commission in the prior case were actuals, not estimates. AIU claims Schedule 14.03 IP G shows $33.522 million of additions used in Staff's calculation of its unsupported percentage. AIU states that a review of IP Ex. 12.4 in Docket No. 04-0476 shows that over $25 million was in service at time of review and, therefore, not an estimate. AIU also asserts that $16.982 million of Completed CWIP Not Transferred to Plant in Service were also actuals, not estimates. AIU says these amounts combined exceed the $33.522 million of additions Staff used in its calculation.

b. Staff's Position

Ms. Everson reviewed AIU's 2003 through 2006 plant additions which it seeks to include in rate base. The objective of such a review, Staff says, is to establish whether the underlying costs for such plant additions are adequately supported by documented evidence. Staff believes that the required support for these plant additions were either deficient in many respects or non-existent. Staff developed a sample of projects for each of the six utilities that were based on Ms. Everson's professional judgment, knowledge, and experience as an accountant. Specifically, for each of the six utilities, she reviewed and analyzed the invoices and the summary listings that were associated with projects having a total dollar value greater than $500,000. Ms. Everson made the assumption that more care and documentation would be given to projects with a larger cost than those with smaller costs; thus, better records would be available to support the larger projects. For each of the six utilities, Ms. Everson developed a sample for which she determined the percentage of unsupported project costs to the total costs of the projects within the sample. The resulting company-specific percentage of unsupported costs was then applied to the total 2003-2006 plant additions for the respective utility to determine the amount of Staff's proposed plant disallowance.

Staff says its review of over 8,700 pages of project invoices and listings that summarized the amounts of such invoices recorded by AIU (referred to by Staff as ―summary listings") resulted in the discovery of numerous problems. According to Staff, adequate support for the plant costs was non-existent or had one or more of the following deficiencies: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that did not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice.

According to Staff, the company-specific percentages of unsupported plant costs are as follows: AmerenCILCO gas: 11.58% electric: 35.45%; AmerenCIPS gas: 25.56% electric: 2.35%; AmerenIP gas: 51.74% electric: 12.78%. Staff states that when these percentages are applied to the respective totals for plant additions from 2003 through 2006, these percentages result in the following proposed plant disallowances: AmerenCILCO gas: $6,563,000 electric: $30,005,000; AmerenCIPS gas: $1,736,000 electric: $2,347,000; AmerenIP gas: $49,810,000 electric: $34,135,000.

According to Staff, AIU's failure to properly document plant additions has a long and contentious history. Staff states that in Docket No. 99-0121, the Commission Order demonstrates CILCO's inadequate support for its pro forma plant adjustments and the untimely production of such information to Staff. Unlike in the current docket, however, Staff says CILCO accepted responsibility in that rate case for its failure to provide the appropriate documentation for its plant requests and recognized it should bear any hardship for failing to provide such documentation. (Staff Initial Brief at 10-11, citing Docket No. 99-0121, Order at 22-27 and 29-30)

Staff claims that in its last electric delivery services rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), AIU again failed to provide sufficient documentation to support its plant costs. Staff states that in those consolidated dockets, the Commission imposed a plant disallowance due to AIU's failure to support its plant additions. (Staff Initial Brief at 11-12, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 13 and 7) Staff says its proposed disallowances in that case were related solely to disputes over documentation of AIU's reasonably incurred costs.

Staff asserts that in the current proceeding, the same pattern from prior rate cases repeats itself. Staff says that in the MHE 3 series of data requests (Staff Data

Requests MHE 3.01-3.06) Staff requested copies of invoices, a listing of invoices, and all loading factors for the projects chosen for the sample for each of the six utilities. AIU provided six compact discs (―CDs") in response during December 2007 through February 19, 2008. Staff indicates that the CDs contained approximately 8,700 pages of documentation, including the summary listings and copies of invoices. Staff adds that the response on February 5, 2008, dismissed the request for all loading factors as being ―. . . unduly burdensome and unreasonably time consuming . . . . Further, the information is not relevant, nor material, nor likely to lead to the discovery of admissible evidence." (Staff Initial Brief at 12-13, citing Staff Ex. 14.0R, Att. A) Staff says it understood this to be the entirety of support that AIU could provide for the sample of plant additions. The information in the six CDs and the narrative response to the MHE 3 series formed the basis for Staff's analysis and recommendation.

Staff claims that AIU's initial productions in discovery did not contain all of the requested documentation, nor, in Staff's view, did it contain sufficient documentation for the plant costs it seeks to recover from ratepayers. Staff complains that AIU provided additional information in its rebuttal testimony that should have been provided earlier in the case when such information was requested by Staff. Staff says Ameren Ex. 19.12 includes a detailed listing that attempts to provide a reason why AIU considered disallowed amounts as supported. For some line items on Ameren Ex. 19.12, Staff says AIU indicates: ―[c]an't locate the invoice." (Staff Initial Brief at 13, citing Ameren Ex. 19.12, Sch. 1-CILCO-E, at 10-12.) Staff adds that Ameren Ex. 19.12 also includes Schedules 8-13, provided on a CD which contained 83 separate pdf files, containing invoices and supporting documentation as requested in the MHE 3 series of data requests, named by schedule and part. In Staff's view, the provision of this volume of information without a clear organizational framework at the rebuttal stage of the proceeding made it impossible for Staff to complete a thorough review.

Staff says it reviewed a sampling of the information provided in Ameren Ex. 19.12 and sent data requests to AIU. Staff claims the data requests sought information regarding the explanations provided in Ex. 19.12 to attempt to determine if the explanations were indeed the reasons why the invoice amounts and AIU's summary listings did not match. Staff asserts that AIU's data request responses were vague and in some instances contradicted Ex. 19.12, and failed to fully reconcile the differences between the invoice amounts and the amounts shown on the summary listings. One of the reasons provided with Ameren Ex. 19.12 for the mismatch between the summary listings and the invoices, Staff states, were ―purchase adders." Staff claims that AIU never provided any information as to what the appropriate purchase adder was for AmerenCILCO and AmerenIP. According to Staff, AIU provided no indication of what the fixed rate charge was or when it would be applied.

Staff argues that by providing information in rebuttal testimony rather than in responses to discovery, AIU has deliberately attempted to withhold information to support its request for recovery of plant additions in an adequate and timely manner. Such litigation strategy, Staff contends, is a common theme in the prior AIU cases.

Staff believes the Commission has given AIU more than enough warnings and must hold AIU accountable for the consequences of its actions.

Staff states that when it requested a separate identification of the type and amount of all loading factors in connection with its review of plant additions, AIU protested that this would require an examination of each invoice. Staff says it accepted AIU's explanation that this would be unduly burdensome and time consuming. Staff, however, claims that it could not accept invoices as support for a different level of costs than was reflected on the invoice. According to Staff, AIU claims it provided Staff with the information necessary to complete a review of plant additions; however, Staff says AIU did not provide it with sufficient information to support all of the plant additions that AIU proposed be included in rate base. Staff argues that it does not know what documentation AIU possesses or the level of burden of producing the documentation. According to Staff, AIU knows what documentation it possesses, the difficulty of producing it, and the consequences of failing to produce support for its plant additions.

Staff asserts that AIU is aware that unsupported plant additions will not be included in rate base, and is aware of the importance of locating and producing support for plant additions. Staff contends that if AIU deems support to be overly burdensome to provide, Staff can complete its analysis without the additional documentation but, since costs can not be included in rate base unless they are supported, the failure to provide support will inevitably result in adjustments. According to Staff, AIU's provision of breakouts of the costs associated with each project in response to Staff data requests MHE 3.01-3.06 was an ineffective substitute for providing the loading factors. Staff states that gross loading factors were provided, not specific amounts for individual line items for which there were differences between the line item on the summary listing and any invoice. In Staff's view, it was not clear how much of the gross amounts in the breakouts related to such items and how much related to items for which no supporting document was provided.

Staff also argues that compliance with initial filing requirements does not equate to bearing the burden to prove plant additions. Neither, Staff says, does supplying additional information in response to Staff Data Requests and in rebuttal and surrebuttal testimonies necessarily prove the plant additions. According to Staff, it is not the quantity of documents produced or the timing of when the documents are produced that determines whether AIU has met its burden of proof. Staff states that the plant additions for which AIU provided invoice-by-invoice support were allowed by Staff.

According to Staff, AIU is apparently claiming that it has made a showing of the costs necessary to provide service by providing the minimum filing requirements and what amounts to a mountain of paper. Staff states that Part 285 simply provides the minimum filing requirements. Staff argues that providing large quantities of documents that can not be reconciled to the general ledger is not sufficient to satisfy AIU's burden of proof under Section 9-201(c) of the Act. Staff claims the documents AIU provided to support plant additions were replete with deficiencies.

In Staff's view, AIU‘s reliance on City of Chicago for the premise that it need only make a —showing” of the costs necessary to provide service is misplaced. Staff states that AIU is proposing to include plant additions, for which it failed to provide support, in rate base. Staff argues that absent external support, AIU has not shown by a preponderance of the evidence that plant additions are reasonable. Staff also refutes AIU‘s reliance on Docket Nos. 83-0537/84-0555 (Order at 183-184). Staff insists there is no presumption of reasonableness.

Staff says AIU argues that the basis for Staff‘s plant additions adjustment is only because of issues pertaining to the documentation of expenditures. AIU, Staff adds, distinguishes this adjustment from one based on a cost being imprudent or unreasonable. Staff calls this hair splitting. Staff repeats that utilities are required to retain records and to support costs for a reason.

Staff asserts that AIU is in violation of 83 Ill Adm. Code 420, —The Preservation of Records of Electric Utilities” (—Part 420”), and 83 Ill. Adm. Code 510, —The Preservation of Records of Gas Utilities” (—Part 510”). Staff states that the rules require that the detail summary and distribution records supporting journal vouchers for plant accounts be retained for the seven years prior to the date as of which the original costs of plant have been unconditionally determined or approved by the Commission.

Staff says AIU attempted to excuse its failure to retain its records and to support its costs by pointing to different corporate ownership of CILCO and IP prior to their acquisition by Ameren. Staff says the implication of AIU's statement is that this somehow absolves it of its record preservation obligations. Staff states that each of the acquired AIU companies was a public utility company prior to Ameren‘s acquisition and AIU operated AmerenUE in Illinois prior to merging with the other public utility companies.

According to Staff, AIU complains that Staff refused to take into consideration the timing of the transactions and the changes in systems and corporate ownership when recommending a disallowance due to missing invoices or unsubstantiated amounts. Staff says AIU has made this claim in two prior rate cases, one as far back as 1999, and in each case, this excuse was rejected by the Commission. Staff argues that it is irrelevant that AIU had no control over the actions of the prior owners. Staff says that when AIU was seeking approval of its reorganizations, it committed to be subject to all of the rules and regulations and should be held to its commitment.

Staff adds that AIU failed to notify the Commission within 90 days of the destruction or loss of such records, as required by Section 420.70 of Part 420 and Section 510.70 of Part 510. Instead, Staff asserts that only after it raised this as an issue did AIU provide the required notice to the Commission that CILCO‘s September 2000 through December 2002 accounts payable vouchers were prematurely destroyed in September 2003. Staff states that this notice was provided to the Commission significantly beyond the 90 days required by Sections 420.70 and 510.70, and it does not cover other documents that AIU has been unable to provide for AmerenCIPS and AmerenIP for which no explanation has been provided.

Staff states that although AIU witness Steinke admits that it must accept responsibility for its inability to produce plant cost documentation sought by Staff in this case, he also claims that AIU is in compliance with the Commission's requirements for preservation of records. According to Staff, AIU can not have it both ways: pretending to accept its responsibility for its failure to produce records and then claiming it is in compliance with the Commission's record retention policies.

Considerable resources, Staff contends, have been spent in this proceeding to provide, explain, and review AIU's support for plant addition costs since its last rate case. Staff maintains that AIU has failed to retain and produce records it is required by administrative rule to preserve. Staff adds that in some circumstances AIU relied upon third parties' records. Staff says that in other circumstances, AIU retracted previously supplied explanations for discrepancies in its documentation. Staff believes that AIU is unable to adequately explain all the discrepancies between its plant invoices and the summary listings. As a result, Staff contends that there is doubt as to whether any of the information provided on Ameren Ex. 19.12, or in exhibits attached to its surrebuttal testimony can be relied upon. Staff argues that there is no reason to believe that at some time in the future AIU will be more able to locate and produce support for these plant additions. Staff claims the support should have been generated at the time the plant was added and there would be no reason that the support was not available in 2008, but would be available in 2009 or 2010. Staff recommends that AIU permanently write-off all plant disallowance amounts ordered in this proceeding and be prohibited from seeking recovery of these amounts in any future rate proceeding. Staff believes a permanent disallowance will close the book on the matter allowing AIU and Staff to focus on more timely issues in the next rate case.

According to Staff, the only argument Mr. Steinke offers to rebut Staff's recommendation of a permanent disallowance is to state that such a disallowance is unduly harsh and would not be a positive event for AIU. Staff maintains this is not the first or second instance in which AIU was put on notice that it must fulfill its responsibility to support its request for recovery of plant costs with adequate and timely documentation. Staff asserts that AIU has failed to do so time and again and in a significant manner. Staff claims the magnitude of the apparent disarray in AIU's records has resulted in the Staff proposed disallowance. Staff maintains that there is no reason to believe that documents unavailable now will materialize before the next rate case.

To provide AIU with a clear incentive to fulfill its obligation of adequately supporting plant costs for which it seeks rate recovery, Staff urges the Commission to permanently disallow unsupported plant costs in this proceeding. Staff asserts that a permanent disallowance would make AIU truly accept its responsibility by accepting the consequences of its failure to retain and/or produce records. To do otherwise, Staff argues, would be tantamount to encouraging AIU to continue the same pattern it has followed over the years of providing inadequate information to support costs that it seeks to have ratepayers pay. In addition, Staff asserts that failure to order a permanent disallowance would allow AIU, in the next rate case, to focus on producing documentation for the plant additions added subsequent to this proceeding.

According to Staff, if the Commission were to allow unsupported costs to remain in the AIU plant accounts, those same disallowed plant costs would be included in rate base in all future rate proceedings. Staff alleges that all future proposed revenue requirements would include a return on what it calls phantom plant and a recovery of the phantom plant through depreciation expense. Staff asserts that a permanent disallowance of the costs would remove the costs from the AIU plant accounts thus removing this possibility.

In its Reply Brief, Staff states that, generally, the plant in service balance should always be determined by beginning with the last original cost balance ordered by the Commission, adding properly supported plant additions and subtracting documented retirements. Staff asserts that to start with a number that includes plant additions that the Commission found to have deficient documentation in a previous case improperly ignores and overrides the previous Commission order.

Staff claims that the notion that the Commission has not ordered permanent disallowances for lack of documentation does not bear scrutiny. Staff says the Commission in four previous dockets made adjustments for unsupported plant additions due to poor or non-existent utility records. According to Staff, the effect of these orders is a permanent disallowance since the records were found to be non-existent or so deficient that the plant additions can not be substantiated at the time of the orders or in a subsequent proceeding.

Staff states that in Docket No. 04-0610, a rate proceeding of New Landing Utility, Inc., the Commission laid out how the plant-in-service balance is determined:

> Staff witness Griffin calculated utility plant by beginning with the allowed level of Utility Plant for ratemaking purposes found in the previous rate case. (See 79-0676/79-0675 (Cons.) at 11, 15 (Jan. 14. 1981)). Plant additions supported by documentation were added to the water and sewer rate bases. . . . Having reviewed the entire record in this proceeding, the Commission cannot accept the AG's proposal to utilize the Company's Annual Report as the basis for establishing rate base in this proceeding. It is clear that NLU's accounting procedures and records since the last rate case are flawed. Contrary to the AG's suggestion, the Commission simply cannot rely upon NLU's annual report and underlying accounting records to set rates in this proceeding. Thus, Staff's recommended approach to establishing rate base in this proceeding is adopted. (Order at 4-5)

In Docket Nos. 03-0398/03-0399/03-0400/03-0401/03-0402 (Cons.), a rate proceeding of Cedar Bluff Utilities, Inc., Apple Canyon Utility Company, Charmar Water Company, Cherry Hill Water Company, and Northern Hills Water and Sewer Company, Staff says the Commission adjusted the current revenue requirement to reflect previous disallowances made by the Commission in the previous rate case. The order states:

> Staff proposed adjustments to reflect rulings in previous Commission Orders. (Staff Group Ex. 2.0). These adjustments reduce rate base for Apple Canyon and Charmar. These adjustments also incorporate adjustments that were never made from the Commission's order in Docket No. 90-0475/92-0401, which concerned Apple Canyon, and Charmar's short form filing with a test year ending December 31, 1989. The Companies did not contest the adjustments. (Order at 12)

Staff claims the order also lends support that the Commission expects plant additions to be supported by documentation as the language below indicates:

> Staff proposed adjustments to reduce the test year plant amount to reflect those additions and retirements that the Companies could not verify. (Staff Group Ex. 2.0). These adjustments decreased plant for Cedar Bluff, Apple Canyon and Charmar. Cedar Bluff's test year plant was reduced by the amount of additions and retirements, for which, it could not provide any supporting documentation. Both Apple Canyon's and Charmar's test year plant were reduced by the amounts of additions, for which the Companies could not provide any supporting documentation. Corresponding adjustments to accumulated depreciation, depreciation expense, and accumulated deferred income taxes were also made. The Companies did not contest any of these adjustments. (Order at 11)

In Docket No. 98-0045, a rate proceeding for Northern Hills Water Company, Staff claims the order refers to the company recording plant adjustments permanently on its books and records for adjustments from the prior rate case not reflected in the company's filing:

> The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and on Appendix C, Schedule 4. The Company agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 4)

In Docket No. 98-0046, a rate proceeding for Del Mar Water Corporation, the Order states:

> The Company accepted Staff's recommended rate base adjustments as set forth on Appendix A, Schedule 4, and it agreed to record the plant adjustments permanently on its books and records when the transactions are complete. (Order at 3)

Staff believes a permanent disallowance would make it clear to AIU that it can not continue to promise to do better, but continue to fail to comply with Commission rules.

AIU witness Taylor claims that Ms. Everson's sampling methodology was flawed since the entire population of plant additions was not sampled. Staff states that Mr. Taylor conceded that it is not within the scope of his testimony to review the legitimacy of Staff's conclusions regarding plant additions. According to Staff, AIU witness Batcher criticized Ms. Everson's reliance upon a judgmental sample since unlike statistically based random samples, accuracy of judgmentally selected samples can not be assessed in a scientific or objective manner.

Staff states that in performing her plant additions analysis, Ms. Everson narrowed her review to projects $500,000 or more because she expected, based upon her professional experience, that these larger projects would have better documentation and cost support than would smaller projects. Staff argues that in limiting her sample to the larger projects, Ms. Everson's recommended adjustment to AIU's plant is conservatively low. In Staff's view, if Ms. Everson's analysis is to be faulted, it should be faulted for perhaps not recommending a greater disallowance.

Staff claims AIU has the burden of proof to show that the application of Ms. Everson's judgment and experience has led to an incorrect result. According to Staff, AIU did not provide any evidence to show that had Ms. Everson utilized a statistical sample, the resulting disallowances would be materially different than what has been recommended by Staff.

In its Reply Brief, Staff claims that AIU's position on statistical sampling and on extrapolating the result of an analysis on a sub-group of a population to the larger population that was not statistically sampled directly conflicts with its own method for analyzing the reasonableness of AMS costs allocated to AIU. Staff states that in his study of AMS services and costs, AIU witness Adams chose a sample of 197 service requests ("SRs") out of 881 SRs with allocation factors that affected AIU. Staff says he selected his sample by choosing SRs that had charges allocated to Administrative and General ("A&G") accounts and that totaled more than $50,000. Staff states that Mr. Adams used the results of his analysis of this judgmental sample from a sub-group of the population to assess the reasonableness of AMS' costs allocated to each of the Ameren subsidiaries. Staff says the basis for the $50,000 criterion was his professional judgment. According to Staff, Mr. Adams assumed that if the larger dollars are being charged and allocated in an appropriate manner, that everything under $50,000 was as well. Staff contends that this judgment is similar to Ms. Everson's reliance on her experience and judgment that the larger projects would have better documentation and cost support than would smaller projects. Staff argues that since AIU continues to assert that Mr. Adams' AMS analysis should be relied upon by the Commission, it can not dismiss Ms. Everson's plant additions analysis.

Staff states that while Ms. Everson prepared no written plan that does not mean that no plan was developed prior to her review of plant additions. Staff says it requested and received a listing of projects of $500,000 or more prior to selecting its sample or conducting its review. Staff claims its request for information regarding plant additions projects with a total greater than $500,000 demonstrates that a plan existed to review plant additions projects with a total greater than $500,000. In addition, Ms. Everson indicated that she determined based on her experience at the Commission that it is reasonable to expect that more care in documentation is given to larger projects than to smaller ones; thus, better records would be available to support the larger projects.

In its Reply Brief, Staff says AIU's assertions regarding the differences between Staff's review in this case being different from any other case is speculation and should not be accorded any weight. Staff claims that although AIU does not admit it, a very similar review was conducted in its last rate proceeding where plant additions were subject to a disallowance for lack of supporting documentation. Staff also believes it is not appropriate for each of Staff's reviews to be constrained by that which has been performed in prior cases. According to Staff, AIU is attempting to convey the notion that not only should Staff's review in this case follow the same review as in the cases it cited, it is also claiming that Ms. Everson's adjustment must be disallowed since it was at odds with other Staff witnesses in this case. Staff contends this claim is irrelevant because Ms. Everson's review concerned whether AIU had sufficient documentation to support its plant additions, whereas Mr. Rockrohr's adjustments to plant additions concerned whether plant held for future use should be included in rate base and whether AIU was prudent in its purchasing of certain security installations. Staff claims that since the focus of each review was different, it is unrealistic to contend that one Staff member's analysis is flawed because it is different from another analysis conducted by another Staff member.

According to Staff, AIU witness Stafford incorrectly criticized Ms. Everson for including AmerenIP's 2004 gas plant additions when she applied the disallowance adjustment percentage to the total plant additions. He argued that IP was allowed a certain level of pro forma plant additions in its last rate case, Docket No. 04-0476. Taken to its logical conclusion, Staff says this argument incorrectly asserts that approved pro forma plant additions in a prior rate case do not require substantiation with supporting cost records in the next rate case. In Staff's view, this argument is unreasonable and inconsistent with the Commission's practice. Staff argues that pro forma amounts are essentially estimates of plant costs expected to occur within a defined period from the chosen historical test year and subject to certain restrictions as defined in 83 Ill. Adm. Code 287, —Rate Case Test Year." Staff claims the pro forma amounts for a specific plant can and do vary from the amount actually incurred for the same plant. Staff believes that the prior approval of a plant's cost when it was a pro forma item in a prior rate case has no bearing on its approval as an actual plant cost in a later rate case. In Staff's view, all plant costs for which a utility seeks rate recovery needs to be adequately supported regardless of whether they were once approved as pro forma amounts.

The amounts in the current filing for AmerenIP's 2004 plant additions, Staff argues, are not the same pro forma amounts that were allowed in the prior rate case. Staff says those amounts were allowed as pro forma amounts that would be placed into service after the 2003 test year in that docket. Staff adds that AIU's response to Staff Data Request MHE 14.01 stated: ―The current IP Gas 2004 capital additions amounts included in the current IP Gas filing are not identical to the pro forma plant additions that were considered in Docket No. 04-0476. The amounts related to the IP Gas 2004 capital additions included in the current filing include actual expenditures incurred in both 2003 and 2004 and placed in service in 2004.” (Staff Initial Brief at 24, citing Staff Ex. 14.0R at 25) Staff maintains that its application of the adjustment percentage to all of AmerenIP gas plant additions is appropriate, since the plant additions in this case represent actual project costs which are not the same amounts as the pro forma amounts allowed in Docket No. 04-0476.

Staff states that in its review of the invoices and summary listings reflecting the invoices recorded by AIU, duplicate amounts were noted and disallowances were proposed. Ameren witness Batcher criticized Ms. Everson, for allegedly failing to document her procedures for identifying duplicate invoices rendering AIU unable to determine if she conducted adequate searches to find an adjustment to the duplicate on the summary listings. Staff asserts that Ms. Everson fully described in her rebuttal testimony the type of review she performed to make the determination that there was a duplicate invoice for which no offsetting adjustment existed on the summary listing. Staff asserts that Ms. Everson‘s review included a comparison of a suspected duplicate invoice with the previously reviewed invoice to verify the identical invoice, number, date, vendor, amount, and service or goods provided. Staff finds AIU's criticism to be without merit.

AIU, Staff argues, essentially faults Staff for not granting it the benefit of the doubt when Staff disallowed invoices that were not billed to the correct entity. Staff says that AIU cites the alleged practice of the IRS. Staff claims that AIU does not appear to fully understand that it is AIU‘s responsibility, not Staff‘s, to prove that the invoices it proffers as support for costs it seeks to recover from ratepayers are legitimate.

In Staff's view, the problem with AIU's position is apparent in Mr. Stafford's testimony that an invoice sent to AmerenCIPS but later charged to AmerenCILCO contained nothing that would indicate the invoice should have instead been sent and billed to AmerenCILCO. (Staff Initial Brief at 25-26, citing Staff Cross Ex. Stafford 1 and Tr. at 430-433) Staff provides another example where an invoice sent to Ameren Energy Resources‘ Purchasing Department but charged to AmerenIP contained no information indicating AmerenIP was the correct entity to be billed (Id., citing Staff Cross Ex. Stafford 2 and Tr. at 433-436) Given the dearth of information on the invoice as to which entity should correctly be charged, Staff argues that it can not in good conscience give AIU the benefit of the doubt and assume incorrectly billed invoices are automatically legitimate.

According to Staff, AIU claimed that the project manager determined whether billings to another Ameren company were appropriately associated with a particular project. Staff says that Mr. Stafford, however, stated on cross examination that there is no information discernable from a review of the invoice to support this explanation. Staff says that unlike AIU, it can not presume that any review was performed or that any project manager direction was provided to substantiate AIU's claim. Staff asserts that no supporting documentation in the form of source documents, such as invoices that are either marked by the project manager or the accounts payable personnel, or some other internal document that would indicate the project manager's decision regarding which projects to assign costs was provided. Staff says AIU also inappropriately suggests that since the work was performed for the benefit of an AIU utility, it does not matter that an AmerenCILCO customer might be charged for project costs that benefit AmerenIP. Staff disagrees with that view and believes that ratepayers of one utility should not be penalized with higher rates as a consequence of AIU's failure to demonstrate that costs are recorded to the right utility.

According to Staff, Dr. Batcher also fails to recognize that there is a substantial difference between expense payments for tax purposes and the proof needed for rate recovery. For tax purposes, Staff says it makes little difference which company makes payment where a consolidated tax return is filed because in the end, all revenues and expenses are combined into a single tax return. Staff argues, however, that the Commission review for setting rates is a different standard. The Commission, Staff says, must decide which of the six AIU operations is to be credited for payment. Additionally, Staff says a decision must be made whether the payment is to be classified as an expense or a capitalized item. Staff asserts that if the payment is classified as an expense, questions concerning whether it is reflective of normal operations, whether it should be amortized, and whether the unamortized balance should be given a return must be answered. If the payment is classified as a capitalized item, Staff says decisions concerning the proper account and the depreciable life for purposes of calculating annual depreciation expense must be answered. Staff claims its task is more complex than just confirming payment by any one of the utilities and can not be accomplished unless the individual utilities provide the appropriate records in a timely manner.

Staff asserts that in many invoices it reviewed, the amounts did not match up to the amounts listed in the summary listing of invoices recorded by AIU. According to Staff, AIU claims only a partial amount on the invoice should be matched with the summary listing in the absence of any indication on the summary listing or on the invoice. Staff says AIU offered the explanation on Ameren Ex. 19.12 that the project manager made the determination of which charges on each invoice should be attributed to specific projects. Staff asserts, however, that Mr. Stafford concedes that the invoices contained no indication of the project manager's direction regarding specific invoices.

Staff indicates that Dr. Batcher asserts that where invoice amounts differ from the amounts shown on the summary listing of invoices, a partial amount should be allowed. In Staff's view, the suggestion that partial invoice amounts should be allowed is without merit. Staff acknowledges there could be legitimate reasons for the differences. Staff argues, however, that the knowledge that legitimate reasons for the discrepancy may exist does not substitute for documentary evidence that reconciles and substantiates why invoice amounts differ from the amounts actually recorded by AIU on its books. Staff contends that AIU can not offer any credible explanation for some of the differences.

According to Staff, Dr. Batcher's assertion that some, if not all, of the differences would have been easily ascertainable by simply learning more about the business is also without merit. Staff claims this shows Dr. Batcher's lack of knowledge about which party bears the burden of proof. Staff maintains that AIU has responsibility to provide adequate documentation to support the costs included in its rate filing. Staff says that while it has spent considerable time and effort to make sense of AIU's plant records, Staff has no obligation to further expend its limited resources to help AIU satisfy its burden of proof.

Staff says Dr. Batcher asserts that Staff should have worked harder to find a way to make the illegible copies of invoices AIU provided legible. This assertion, Staff argues, indicates a fundamental misunderstanding about which party bears the burden of proof. According to Staff, AIU had every opportunity, before it filed the rate case, to ensure it had adequate, complete, and legible documentation for the costs it seeks to recover from ratepayers. After learning from Staff's direct testimony of the illegibility of some of its invoices, Staff says AIU once again had an opportunity to rectify the situation by providing legible invoices or alternative evidence that would adequately substantiate the costs in the illegible invoices. Instead, Staff claims AIU complained that Staff should have printed the illegible invoices on a different printer and played with various printer settings until it could read the invoice. Staff argues that if AIU's criticism were accepted then there would be no incentive for any utility to submit legible copies of any document to support costs it seeks to recover from ratepayers. Staff says reviewing and analyzing documentation of this magnitude is challenging enough without having to add what should be AIU's obligation: producing legible documentation of its costs.

Citing the Commission's decision in Docket No. 01-0701, Staff argues that it should not be ratepayers' responsibility to pay for late payment charges. Staff also refutes AIU's suggestion that Use Taxes and Purchasing Rate/Fixed Charge explain discrepancies in various invoices. In the latter case, Staff maintains that AIU failed to adequately explain the magnitude of such charges and when such charges are applied.

According to Staff, Dr. Batcher complained that Ms. Everson's review of invoices used a zero tolerance approach even though she was dealing with mergers and retired systems for storing the imaged invoices. According to Staff, a zero tolerance approach is reasonable, logical, and accepted in Illinois for reviewing plant records that a public utility has an obligation to retain, and for which AIU has the burden of proof to provide when it is requesting related plant costs be included in the determination of rates.

Staff says AIU criticized Ms. Everson for disallowing costs that are not supported by invoices as some are not retrievable from retired systems, indicating that alternative evidence should have been accepted, or if not extensive, that such missing items should have simply been ignored in Staff's calculation of its disallowance. Staff maintains that the Commission's rules for record retention do not include any exemption for records simply because a utility chooses to retire a system, thus making retrieval more difficult or impossible. Staff restates that AIU and its predecessor companies all were subject to the record retention rules; so it is not valid that some allowance should be made for old or difficult to retrieve records.

Staff argues that since the summary listings were taken from AIU's general ledger, the general ledger is not a supporting source document for amounts that are drawn from the general ledger. In addition, Staff contends that continuing property records and retirement property unit records do not substitute for source documents, nor do they substantiate the cost of plant additions. According to Staff, the information generated through the queries to the general ledger systems was used to compile the list of invoices and voucher numbers. Staff adds that the underlying general ledger queries would simply be a repetition of the process that generated the list of invoices in the first place; it would not provide any additional support for the legitimacy of the costs.

Staff says the premise of AIU's position is that an invoice can be supported by the accounting records. Staff asserts that the source document for the accounting records is the invoice, not the other way around. AIU witness Nelson claims that the electronic transactions recorded on its general ledger can be relied upon to substantiate its costs as they can be independently verified through one of three different ways: 1) the accounts payable system, 2) the contractor system, and 3) the vendor's verifications. Staff notes that Mr. Nelson also testified that data from both the accounts payable system and the contractor system are fed into the general ledger's accounting system.

It is unclear to Staff how reports generated from either the accounts payable system or the contractor system would independently substantiate the costs recorded in the general ledger. Staff claims this reasoning is circular because there is no independent verification of the costs. As to the vendor's verifications, Staff says many vendors did not supply invoices with their affidavits that corroborate the costs in the general ledger. In addition, Staff states that Mr. Nelson testifies that AIU provided the information to the vendor regarding the costs the vendor verified. Staff adds that Mr. Nelson does not indicate how such vendors could have verified those costs over relatively long periods of time, some occurring as far back as 2003. Staff says Mr. Nelson is clear that using the data it has in its general ledger, accounts payable system, and contractor system, AIU prepared the information in the vendors' affidavits which it then had the vendors' sign. Staff believes this is circular reasoning and does not substantiate the costs in the general ledger.

Staff expresses concern about Ameren Ex. 19.12 in that AIU has not retained some of the invoices and has to rely on its vendors to provide invoices, many of which Staff says do not match to the amounts recorded to the general ledger and continuing property records. Staff indicates that AIU was not separately able to confirm from a vendor supplied invoice the reason for the difference, or whether the additional invoice amount was either discounted for payment, or instead charged to another AmerenCILCO project. Based in part on this, Staff questions whether any of the invoices obtained in this manner can be relied upon to provide support for AIU's plant additions. Staff says the Commission can have no confidence that any such invoices are related to the amounts AIU claimed on its summary listings. Staff recommends disallowing these project totals from the determination of AIU‘s plant balances.

Staff indicates that in surrebuttal testimony, Mr. Stafford states that in response to Staff‘s concern regarding vendor-supplied invoices, AIU removed the costs associated with the vendor-supplied invoices that are being relied upon as support for project costs. Staff says it is unclear whether Mr. Stafford intends to mean that AIU has removed the costs associated with all vendor-supplied invoices that were provided to support project costs, or just ones that were disallowed by Staff. Staff claims it is nearly impossible without a line by line review of each item in the original summary sheets to determine if the claim that Mr. Stafford makes regarding the vendor-supplied invoices applies to all vendor-supplied invoices, or just the ones disallowed in Ms. Everson‘s calculation.

AIU witness Livasy provided rebuttal testimony that described the process that IP used for its electronic fund transfers (―EFTs”). IP‘s EFTs contain specific information that Mr. Livasy says was compiled or that existed such as work order numbers, invoice numbers, invoice dates, and vendor numbers to identify contractors. Staff complains that the testimony fails to provide any supporting documentation other than the results of queries on the same system that produced the amounts being tested.

Mr. Stafford claims that Ameren Ex. 19.13 provides support for the EFTs on IP projects. Staff says Ex. 19.13 is a spreadsheet with information on work order numbers, invoice numbers, invoice dates, general ledger amounts, vendor numbers and names, batch numbers, approvals, and the paying entity. The problem with this listing, Staff argues, is that this information came from the general ledger itself, not from an independent source that could corroborate its veracity. Staff says no invoices or contracts or any other evidence that the transfers were reviewed or approved were provided. Staff contends that an internally-generated document such as Ameren Ex. 19.13 which was produced from the same general ledger as the amounts in the general ledger in question only provides support that entries were made, and that funds were transferred from the AIU utility. In Staff's view, Ex. 19.13 does not provide support for the validity of the cost amount, or the applicability of the amount to a specific project, since no vendor invoices are provided. In other words, Staff does not believe the general ledger can substitute for independent third party evidence. According to Staff, there is no audit trail for the electronic transactions or presumably AIU would have provided it with its rebuttal testimony instead of relying on descriptions of the process.

Staff says that in response to Staff Data Request MHE 14.03, which asked AIU to produce the invoices to support its plant additions paid for by EFTs, AIU objected and stated that it was unable to immediately obtain that information. Staff indicates that AIU also stated that vendor payments are based on documented internal processes that provide appropriate controls and authorizations for payment, satisfying vendors, auditors, taxing bodies and regulators including the Commission. Staff asserts that nothing was provided to document those alleged appropriate controls and authorizations. Staff says AIU could produce no Commission order to support its contention that this process had been approved by the Commission and could produce no written communication from the Commission's Accounting Department Manager that indicated approval of the electronic process.

Staff says much of AIU's surrebuttal testimony is essentially supplemental data that was requested by Staff in the MHE 3 series of data requests. Staff claims it is not in a position to know what is the universe of supporting documents for AIU's requested plant additions. Assuming Staff even knows the universe of such documentation, which Staff says it does not, Staff claims the magnitude of the information that needs to be sifted through to uncover problems, such as missing invoices or invoices with discrepancies, takes a significant amount of time. Staff claims it is not in a position to know how many plant assets are involved, thus, Staff can not know how many invoices Staff is supposed to get in support of such assets and related costs. Staff adds that thousands of line items reflecting plant additions and related costs are involved.

According to Staff, this complicated situation is further exacerbated by the fact that many data request responses were supplemented by AIU, and at times, supplemental responses were replaced by corrected supplemental responses. At the same time, Staff says key AIU rebuttal testimony and exhibits were revised after they were filed. In other words, Staff says it has had to contend with a moving target.

Staff asserts that at each point it received responses or supplemental data to prior data responses or to prior AIU testimony, Staff had no basis at those points in time to doubt the completeness of the responses and pursue additional responses from AIU through other means of discovery, such as a motion to compel. Staff believes it is only upon hindsight that one can see that AIU was not forthcoming in its provision of information necessary to adequately support its requested plant additions.

On July 1, 2008, Staff indicates it conducted cross-examination of the AIU witnesses. The purpose of the cross-examination, Staff claims, was not to provide an analysis of the information, but rather to illustrate how such an analysis should be conducted, the difficulty of the analysis, and how much time it would consume. Staff asserts that AIU has consistently provided faulty support for its costs in this proceeding.

Staff recommends that the adjustment proposed in Staff rebuttal testimony be adopted unless the decision maker conducts an analysis of the information provided in AIU's surrebuttal testimony. Staff asserts the analysis of this information would be time consuming and meticulous. In order to determine whether costs submitted with the surrebuttal testimony are supported, Staff says one would begin by comparing Ameren Ex. 43.6, Schedules 1-6 with Ameren Ex. 19.12, Schedules 1-6, to determine for each line item whether Ex. 43.6 contains better information than what was provided in Ex. 19.12. If new information is provided for a given line item, then, Staff says, Ex. 43.6, Schedules 7 and 8 must be reviewed to locate the new support provided. If the support is located, then Staff states that Ex. 19.12, Schedules 8 through 13 must be reviewed to confirm that the information has not already been provided. Similarly, Staff claims that AIU‘s production in response to the MHE 3 series (Staff Cross Stafford Group Ex. 5) must be reviewed to determine that the information was not provided in that production. Staff indicates the documents within these exhibits are organized by utility, utility type, and Project Number. In addition, Staff says it must be confirmed that the cost was not previously allowed in Staff‘s review. If an invoice has been provided with Ameren Ex. 43.6, which has not been previously provided nor accepted by Staff, then Staff says the invoice should be reviewed to determine whether the amount is now supported. Staff asserts that since the information provided in Ameren Ex. 43.6, Schedules 1-8 contains no identification of which line items are new or previously provided, review of this information is difficult and extremely time-consuming.

Staff says the information provided in Mr. Nelson‘s surrebuttal are affidavits of vendors provided in lieu of actual or electronic invoices to support some of AmerenIP‘s EFTs. In addition to the concerns discussed above, the lack of specificity in the wording of the affidavit leads Staff to have concerns regarding the accuracy and reliability of these affidavits. According to Staff, these affidavits essentially constitute hearsay and can not be relied upon by the Commission as adequate support of AmerenIP‘s EFTs for which it could not locate supporting invoices.

In its Reply Brief, Staff says that AIU protests that Staff did not provide AIU with a listing of each and every invoice that Staff disallowed and contends that this shortcoming limited the ability of AIU to refute Ms. Everson‘s analysis. Staff believes AIU's argument is unfounded. Staff argues that AIU has sufficient information to determine which specific invoices were disallowed by Staff. Staff says the argument seems to be that Staff should have provided AIU with a detailed listing of each individual amount disallowed rather than the listing of amounts that Staff allowed. According to Staff, AIU‘s allegation that it is prejudiced by the presentation of Staff‘s adjustment in its work papers does not bear scrutiny. Staff claims AIU was capable of looking through the Summary Listings, identifying which invoices were disallowed, and then checking to see if they were duplicates, bills to the wrong company, etc.

In Staff's view, the complaint about Staff‘s work papers must be considered in context; the Summary Lists and the format which Ms. Everson used to identify her findings came directly from AIU. Staff claims there is no difference between using a slash to indicate Staff identified an invoice on a Summary Listing than AIU using a check to indicate the invoice had been provided. Staff avers that AIU‘s argument, that the very format that it found to be acceptable when making its production was unacceptable when used by Staff, is unpersuasive. Staff says its proposed disallowance was of a percentage of unsupported plant costs; it is not a disallowance of specific invoices or specific unsupported plant costs.

Staff states that while AIU did provide voluminous information throughout the case, it was provided without any roadmap until rebuttal. Staff complains that each new production was provided with nothing to distinguish between new and old information. According to Staff, AIU seemingly equates the quantity of its documentation with quality. According to Staff, the explanations provided in Ameren Ex. 19.12 should have been the starting point provided to Staff for the analysis, but, the descriptions and the road map were provided for the first time in AIU's rebuttal.

Staff claims that AIU's Initial Brief fails to recognize that Staff modified its plant adjustment to eliminate any double-counting of Ms. Everson's adjustment for plant additions since the last rate case and Mr. Rockrohr's adjustments for plant held for future use and security installations. According to Staff, AIU cites Mr. Stafford's rebuttal testimony for this proposition and ignores Staff's rebuttal testimony where Ms. Everson indicates that she made changes to eliminate any double counting or double adjusting of plant additions prior to 2005. Staff says this modification is incorporated into Staff's rebuttal schedules and AIU's assertion regarding double counting is erroneous.

In its Initial Brief, Staff objects to AIU's practice of capitalizing the cost of employee meals. Staff says AIU could not cite a specific provision in the USOA that supports such a practice.

Staff recommends that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities with a copy of the report to be provided to the Manager of the Accounting Department of the Commission by June 30, of each year with the 2007 report to be submitted by December 30, 2008. Staff says the work papers of such audits should be made available and provided to Staff upon request. Staff asserts that requiring AIU to conduct its own internal audit will provide an opportunity for AIU to improve its record keeping skills. The annual reports submitted to the Commission, Staff avers, will provide some assurance to the Commission that AIU is taking steps during the time period between rate cases to improve its plant records. An improvement in record retention, Staff claims, should decrease the contentiousness of plant additions in the next rate case. Staff indicates that AIU witness Steinke stated that AIU has no objection to Staff's recommendation for an annual internal audit.

c. CUB's Position

According to CUB, AIU fails to provide sufficient cost justification to support the cost of plant additions since the last rate case, and therefore these costs should be disallowed. Some of the specific deficiencies include: 1) duplicate invoices, 2) billings to the wrong company, 3) invoices not found that correspond to the listing of invoices provided, 4) amounts on invoices that do not correspond to the listing, 5) project not determinable from the invoice or the invoice is not related to the project, 6) illegible invoices, and 7) certain AmerenIP project amounts that were paid via electronic transfer without a supporting invoice. CUB states that AIU presents Schedules 2.03E and 2.03G asking the Commission to reduce each utility's rate base, but AIU does not provide supporting documentation to allow adjustments to reduce each utility's rate base by the percentage of additions that have occurred since the last rate case and therefore should be disallowed.

d. Commission Conclusion

Because it believes that the costs associated with certain plant additions made since the last rate case have not been adequately documented, Staff recommends that such costs should be excluded from rate base. With very limited exception, AIU disagrees with Staff's position, arguing that it has adequately documented the costs associated with most plant investments. Staff has additional recommendations including that the costs excluded from rate base should be permanently written off and the assessment of fines for AIU's failure to maintain its books and records in the manner required by Commission rules. For the most part, AIU objects to Staff's additional recommendations.

As discussed extensively above, in evaluating AIU's capital investments since the last rate cases, Staff reviewed a sample of projects with total costs exceeding $500,000 for each of the three utilities. Staff concluded that a portion of the costs associated with certain projects were inadequately supported. To develop its proposed adjustments to rate base, Staff applied the percentage of what it considered an inadequately documented amount of plant investment incurred by each utility since its last respective rate case.

As an initial matter, AIU objects to Staff's proposal to apply the percentage developed from projects with costs exceeding $500,000 to the entire universe of plant additions since the last rate case, including those with costs below $500,000. AIU argues that at most, Staff's proposed percentage disallowances should be applied only to those projects with costs exceeding $500,000. Staff believes its assumption that the documentation for larger cost projects would be superior to the documentation for lower cost projects, and justifies the application of its percentage disallowances to both sizes of projects.

Having reviewed the arguments of the parties, the Commission finds that the record does not support Staff's proposal to apply the proposed percentage of disallowed plant costs to projects with costs less than $500,000 since the last rate case. There is no objection to applying a percentage of disallowed costs to the universe of projects with costs greater than $500,000 (from which the sample was derived), and the Commission finds that proposal reasonable. The preponderance of evidence, specifically that regarding sampling methodology, does not support applying a percentage of disallowed costs to projects with costs less than $500,000. The assumption underlying this portion of the proposed adjustment is not adequately supported by the record.

In its Brief on Exceptions, Staff claims there is an inconsistency in the Proposed Order asserting that it rejects a portion of Staff's proposed adjustment to plant additions because Staff used a judgmental based sample rather than a statistical based sample, but did not reject AIU's judgmental based sample as support for AMS costs. The Commission understands Staff's view but believes its concern is misplaced and oversimplifies the situation in which the Commission finds itself. With respect to both of these issues, as is typically the case, the record is not optimal but the Commission must make the best or reasonable decision based upon the record. With regard to plant additions, the Commission believes it is reasonable to apply Staff's proposed disallowance percentage to projects with costs greater than $500,000 but not to projects with costs less than $500,000. With respect to AMS costs, which are discussed more fully below, the Commission's only alternative to accepting AIU's sampling approach is to accept Staff's proposed allocation factor for AMS costs, which the Commission finds wholly unacceptable. Additionally, the Commission notes that in addition to the study of specific AMS costs performed by Concentric, it also performed several benchmarking studies that also provided important support for AIU's assertion that AMS costs allocated to AIU are reasonable. Thus, the Commission's decisions on these two issues must be viewed in the context of the available alternatives as well as the entire record related to each issue.

In its Brief on Exceptions, AIU identifies what it calls calculation errors and clarifications in the appendices to the Proposed Order. Among them is an assertion that the Proposed Order removes from rate base certain plant costs twice. AIU claims that because the starting point for removing plant from rate base in the Proposed Order is its rebuttal position, which already removes from rate base certain plant costs in agreement with Staff, AIU explains that acceptance of Staff's position would remove some of the plant costs twice. In its Brief in Reply to Exceptions, Staff suggests that the adjustment in the Proposed Order is correct and recommends rejecting the proposed change contained in AIU's Brief on Exceptions.

The Commission has reviewed the record and it appears that AIU is correct. Specifically, the Proposed Order applies Staff's proposed disallowance percentages to all AIU projects with costs in excess of $500,000. As AIU suggests, however, the appendices attached to the Proposed Order begin with AIU's rebuttal position. AIU's rebuttal testimony acknowledges that certain plant costs can not be supported; therefore, AIU removed such plant costs from the plant costs it sought to include in rate base in direct testimony. (See Ameren Ex. 19.12 Revised and Ameren Ex. 36.1) Thus, by applying Staff's proposed adjustment percentage, developed in its direct testimony, to all projects with costs exceeding $500,000, the Proposed Order excludes certain plant costs from rate base twice. The Commission finds that in order to avoid removing certain costs from rate base twice, it is necessary to correct the Proposed Order and this correction is reflected in the appendices attached hereto.

Staff proposes that certain costs associated with EFTs by AmerenIP be excluded from rate base because there is inadequate documentary support. AIU argues, among other things, that Staff has not previously proposed similar adjustments, that it thoroughly explained how the EFT process works, and that such costs tie into the accounts payable system and other AIU records.

As an initial matter, the Commission has no objection to AIU, or any other utility, making payments electronically or maintaining records in an electronic format. When questioned by Staff or an intervener in a rate proceeding, however, AIU must be able to document the underlying expenditure. As part of its support for EFTs, AIU provided third party or vendor copies of invoices along with affidavits of the vendors. With regard to this type of evidence, Staff recommends that the Commission treat this information as hearsay and give it no weight when deciding which costs should be included in rate base. The Commission has reviewed the disputed information and finds that it should be given little weight. The documents provided could be accurate representations or copies of invoices; however, it is not clear that is the case. The manner in which AIU solicited its vendors suggests to the Commission that vendors in all likelihood felt pressured to respond in a manner that AIU would deem favorable. The Commission would expect those vendors to want to please AIU so that they could maintain a business relationship. Of course, since the individuals who signed the affidavits were not present, it is impossible to know this or anything else about the veracity of the documents provided by the vendors.

With regard to AIU's assertion that the EFTs are supported by the fact that they match other AIU records, the Commission does not find this argument particularly compelling. As Staff suggests, simply because all of AIU's internal numbers match does not dispel the possibility that AIU's numbers are wrong. An underlying invoice would provide the necessary verification supporting AIU's internal records. Absent such documentation, it is impossible to discount that an improper EFT or an EFT for the wrong amount was initiated, processed, and completed.

Even putting these problems aside, the Commission is concerned that AIU expects the administrative law judges and the Commissioners to review individual invoices and determine whether such invoices are supportive of costs that Staff claims should be disallowed. This is tied directly to the remaining disputed amounts between AIU and Staff; those amounts AIU claims are adequately supported by the invoices provided along with AIU's surrebuttal. In its Reply Brief, AIU states that the Commission can not ignore this evidence and suggests that reviewing it would not be as time consuming and meticulous as Staff suggests. Having undertaken that effort, the Commission disagrees with AIU. The amount of information attached to AIU's surrebuttal testimony is quite voluminous. The more important problem, however, is that there is no context in which the information can be evaluated by the decision maker. In addition to the vendor provided invoices discussed immediately above, there are clearly other invoices attached to AIU's surrebuttal testimony. It is impossible, however, for the decision maker to determine if these invoices correspond to the specific disallowances proposed by Staff. The decision maker has no idea if an invoice for contract labor or any other specific cost corresponds to the specific costs Staff testifies were not previously provided, whether an invoice is duplicative of a previously provided invoice, or for that matter, whether an invoice is totally unrelated to a contested issue. In summary, while AIU provided additional information along with its surrebuttal testimony, the Commission is unable to determine that this information supports the costs that were previously unsupported. Accordingly, the Commission accepts Staff's adjustment on this issue.

Staff also recommends that AIU be required to permanently write-off any disallowance ordered in this proceeding. AIU opposes this proposal, arguing among other things, that it is too harsh. The Commission rejects the proposal to require a permanent write-off. The argument that AIU will not likely be able to provide superior documentation of costs in future rate cases, while superficially appealing, must be rejected. First, AIU argues that it already provided adequate documentation supporting its expenditures along with its surrebuttal testimony. While the Commission has been unable to determine that that is true in this proceeding, it would be unfair to require AIU to permanently write-off investment for which adequate documentation may simply have been provided too late in this proceeding. Second, given the incentive AIU should have to have costs included in rate base, it is possible it would expend sufficient effort between the conclusion of this case and the beginning of its next rate case to uncover adequate documentation of costs disallowed here. To properly balance the interests of ratepayers and shareholders, the Commission rejects Staff recommendation to order a permanent write-off.

Staff argues that AIU is in violation of the Commission's rules regarding records retention and that the Commission should therefore fine AIU. AIU acknowledges some record keeping problems but, nevertheless insists it is not in violation of the Commission's rules and objects to the proposal for a fine. In the context of this rate proceeding, the Commission declines to be further drawn into this dispute between Staff and AIU and rejects Staff's recommendation at this time. Other avenues and forums outside a contested rate case are available to Staff if it wishes to pursue this issue further. The Commission simply reminds AIU that it is expected to comply with all Commission rules.

Staff's recommendation that AIU conduct an annual internal audit of its plant additions and retirements for each of its operating utilities and provide a copy of the report to the Manager of the Accounting Department of the Commission by June 30 of each year, with the 2007 report to be submitted by December 30, 2008, is accepted. The work papers of such audits should be made available and provided to Staff upon request. Finally, any suggestion that ratepayers should be burdened with undocumented costs is not well taken. If costs can not be documented, they will not be reflected in rates, regardless of ownership changes or anything else.

As for Staff's late arising concern regarding the capitalization of employee meals, the record of this proceeding contains insufficient information to make an informed decision and insufficient data to make an adjustment if the Commission decided one were warranted. In any event, the Commission urges AIU and Staff to consider whether it is appropriate to include in rate base the capitalized cost of employee meals. For AIU, this is something it may wish to consider investigating immediately and, perhaps discussing with Staff, in an attempt to avoid an unnecessarily contested issue in its next rate case.

2. Plant Additions Disallowed in the Last Rate Case

a. Staff's Position

Staff witness Everson proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), and which she says AIU was still unable to provide supporting documentation. Staff reports that in rebuttal testimony, AIU witness Stafford agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Mr. Stafford recalculates Staff's proposed disallowance presented on Staff Exhibit 2.0R, Schedule 2.07 to reflect the portion of such additions that AIU concedes are unsupported, but reduces the proposed disallowances to reflect additional supporting documentation that AIU provided. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff claims the amounts on some of the invoices provided do not match with the amount of the asset listing. According to Staff, AIU has not provided the specific reasons that explain why a particular invoice amount does not agree with the asset listing. Staff says it still can not verify that the costs of plant additions that were put into service at least four years ago that the Commission disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base.

According to Staff, Mr. Stafford complains that Ms. Everson does not provide insight into which submitted invoices were accepted or rejected. Mr. Stafford claims that Staff does not appear to have conducted any review of the additional evidence AIU submitted. Staff says it had already reviewed the evidence presented in the previous rate proceedings and had also reviewed the evidence presented in the preparation of direct testimony. Staff claims that AIU admits that it did not have appropriate documentation for all of the contested plant additions and offers a multitude of reasons why a difference could exist. Staff says AIU does not identify the reason for each of the differences. Staff claims it investigated those same general reasons that AIU provided for the plant additions since the last rate case and found extensive follow-up and analysis was required. Staff submits that it should not have to work to prove that documentation does not exist. In Staff's view, if documentation exists, then AIU should provide it. Staff submits that if AIU does not provide documentation, then the additions should be disallowed. Staff states that these plant additions have been in service for over four years and AIU has been working on this case since January/February of 2007. According to Staff, the Commission should find that the burden rests with AIU as required by Section 9-201(c) of the Act.

In its Reply Brief, Staff insists that Ms. Everson reviewed only a sampling of the information and indicated that AIU had attempted to rebut this adjustment with reasons similar to those it used to rebut the disallowance of a percentage of plant additions since the last rate case. Staff states that the new information provided reinforces its concerns about AIU's inability to support plant additions. Staff says AIU's responses to Staff's inquiries about the rebuttal information reinforced instead of quelled Staff's concerns.

Staff asserts that AIU‘s responses regarding the deficiencies either retracted previous explanations or offered vague and non-specific information which cast doubt on the integrity of all of the explanations offered to the extent that Staff could not accept the explanations.

b. CUB's Position

In its Initial Brief, CUB supports Staff's proposed adjustments to rate base.

c. AIU's Position

AIU alleges that as with her adjustment for additions since the last rate case, Ms. Everson has not identified which specific invoices are at issue. AIU asserts that although it asked to be told which of Staff's two reasons for rejecting an invoice applied to each rejected invoice, Staff did not provide sufficient information to enable AIU to respond to Staff‘s proposed disallowance. AIU complains that it was necessary to conduct an analysis of the three projects for both AmerenCILCO and AmerenIP where Staff does not fully accept all additional supporting documentation.

According to AIU, it appears the primary reason Staff deemed an amount to be unsupported for AmerenCILCO is that taxes were paid for an invoice amount. According to AIU, this is not a valid reason to exclude an amount as unsupported. AIU says if AmerenCILCO was exempt from tax it would be a valid reason, but AmerenCILCO does have to pay tax where applicable. A review of two of the amounts in question, AIU states, indicates the amount deemed to be unsupported is exactly equal to 6.25% of the accepted amount for the invoice in question, which corresponds to the tax rate in effect at the time of said purchase.

With regard to AmerenIP, AIU claims that the primary reasons Staff deemed an amount to be unsupported are that two or more invoices are split between projects, or that project and/or work order numbers do not directly correspond to the project in question. AIU argues the fact that two or more invoices are split between projects is not a valid reason to exclude an amount as unsupported. According to AIU, if work is performed by a supplier for more than one project, then it is appropriate that such amounts should be accounted for separately. AIU alleges that in each of these examples, the supervisory personnel that approved said invoice or invoices determined that such costs should be split, with only a portion assigned to the project in question. AIU asserts that to handle this situation any differently would be incorrect, and is no reason to disallow a cost for recovery.

AIU argues that although Ms. Everson continues to recommend disallowance of plant additions disallowed in the last rate case in her rebuttal testimony, she does not challenge or respond to the positions or arguments Mr. Stafford makes in his rebuttal testimony. AIU alleges that her proposed adjustments for previously disallowed additions do not consider additional supporting documentation provided by AIU in rebuttal. AIU claims Staff has provided no meaningful support for these proposed disallowances.

Ms. Everson, AIU says, claims that AIU's rebuttal on this issue is similar to that regarding plant additions since the last rate case. AIU asserts that its rebuttal on this issue is quite different from its rebuttal regarding plant additions since the last rate case. AIU states that for the 20 projects identified as unsupported in Staff Ex. 14.0, Schedule 14.07, AIU provides additional evidence in rebuttal supporting a portion of the proposed disallowed dollars for 6 of the 20 projects. For the remaining projects and dollars, AIU says it reflects an adjustment to reduce plant additions included in rate base in Mr. Stafford's rebuttal testimony. AIU claims 18 invoices support dollars at issue in six projects. This additional documentation, AIU argues, should have confirmed for Staff that neither of Staff's previously stated reasons for disallowance was valid for the majority of the costs. According to AIU, in the amounts cited, either the amount at issue was fully explained and reconciled, or neither reason given by Staff for the disallowance applied to the invoice at issue.

In its Reply Brief, AIU agrees that some of the previously disallowed additions remain unsupported. AIU says it is not seeking rate base recovery for those items; however, it is seeking recovery for additions that it claims are now supported. AIU asserts it has supported $1,019,753 in plant additions that were disallowed in the last rate case and Staff provides no specific basis why this evidence is insufficient. Because Staff's adjustment is calculated as a percentage of total plant additions selected for review, AIU believes Staff's proposed adjustment should therefore be reduced from $39,554,000 to $22,991,000.

d. Commission Conclusion

Staff proposes reducing AIU's electric rate bases for plant additions that were disallowed in AIU's last electric delivery service rate proceeding and for which it says AIU was unable to provide supporting documentation in this proceeding. Staff reports that in rebuttal testimony, AIU agrees with Staff's adjustment for AmerenCIPS and agrees that a portion of the plant additions are still unsupported for AmerenCILCO and AmerenIP. Staff does not recommend accepting all of the additional supporting documentation that AIU provided. Staff says it can not verify that certain costs disallowed in the prior AIU electric rate proceedings are the right costs to be included in rate base. According to Staff, the costs were not supported either because the invoices did not correspond with the listing of invoices provided or because the amounts on the invoices did not correspond to the amounts on the listing.

The Commission has reviewed the testimony as well as the arguments regarding plant investment that was excluded from rate base in the previous rate case. Despite AIU's assertion that it has adequately documented these investments, it is not clear to the Commission that is the case. As the Commission understands it, Ameren Ex. 19.6, Schedules 4 through 7, is intended to provide the documentation. The Commission, however, is unable to sort through the hundreds of pages of invoices and determine if these documents establish the costs previously disallowed are adequately documented. While documents were provided, the Commission is unable to determine even if the invoices provided relate to the plant at issue. AIU is mistaken in its apparent assumption that it can provide a large number of invoices and the Commission will either assume the invoices support the costs at issue or can somehow effectively evaluate the invoices with no explanation. The Commission has no basis to make a determination that the invoices and documents support the costs at issue here. As a result, the Commission accepts Staff's proposal to exclude from rate base the disputed costs that were also disallowed in AIU's last rate case. Staff's proposed adjustments are quantified in each of the three Schedules 14.07-E attached to Staff Ex. 14.0.

3. Property Held for Future Use

a. AIU's Position

On April 3, 2006, AmerenCIPS purchased 31.28 acres, near the intersection of Seminary Road and Bockstruck Lane in North Alton, Illinois, for $375,935. The land was purchased for AmerenCIPS to construct a new substation to be known as the North Alton Bulk Distribution Substation ("Substation"). AIU anticipates that the Substation will be in service by 2014. AIU indicates that the Substation is necessary to serve existing and future load in the northern and northwestern portions of Madison County.

AIU proposes that AmerenCIPS' investment in the land be included in rate base even though it is not currently being used to provide utility service. AIU argues that plant held for future use is a traditional component of rate base, which allows a utility to implement prudent, long-term planning strategies. Under Chicago v. Illinois Commerce Commission, 133 Ill. App. 3d 435, 441 (1st Dist. 1985), AIU understands that plant held for future use may be included in rate base if there is a plan to put it into service within 10 years of the test year. AIU also contends the Commission has also allowed plant held for future use to be included in rate base even beyond this 10-year period where the investment is shown to be "reasonable and the property should be retained; that a significant lead time was required between acquisition of a plant site and plant completion; and that long-range planning was necessary." (Id.)

Due to the long lead-times required for routing and obtaining a certificate of convenience and necessity from the Commission for a 138kV transmission to supply the Substation, as well as the lead times for engineering, design, material acquisition, and substation construction, AIU indicates that AmerenCIPS must beginning planning for future load growth in the area now. AIU acknowledges that the parcel it purchased to accommodate its plans is most likely larger than what it will need for the Substation, but asserts that the seller wanted to sell the entire tract and not split the property. In AIU's view, it was necessary, prudent, and useful to ratepayers to purchase the entire parcel for purposes of building the Substation.

AIU urges the Commission to reject Staff's recommendation to disallow this $375,935 investment from rate base. AIU avers that Staff witness Rockrohr does not claim that the purchase of the property at issue was not prudent, but rather Staff takes the position that the land should be removed from rate base because it will not be used and useful until the Substation is constructed and placed in service. AIU argues that Mr. Rockrohr does not apply the appropriate standard when evaluating plant held for future use, and that to apply his standard would be the same thing as disallowing plant held for future use altogether.

AIU also disagrees with Mr. Rockrohr's claim that inclusion in rate base would be more appropriate in a future rate proceeding. AIU states further that he appears to take issue with the Commission's policy on plant held for future use itself. AIU submits that there is no evidence supporting Mr. Rockrohr's claim that a shorter standard time period for including plant held for future use in rate base is warranted where rate cases are filed more frequently.

b. Staff's Position

Staff recommends that the Commission disallow from rate base $375,935 relating to a parcel of property on which AmerenCIPS intends to build a substation to be in service in 2014 or after. Mr. Rockrohr recommends that the Commission disallow the cost for this parcel for various reasons. He submits that AIU did not demonstrate that the property will ever actually be used for the Substation, nor did AIU provide sufficient evidence to show when the Substation will be in service, should it even be built. Mr. Rockrohr also contends that the evidence shows that even if the Substation is built, AmerenCIPS will utilize only a fraction of the parcel that it purchased. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS can adequately demonstrate that the subject parcel will be placed in service within ten years of the test year. He suggests that the Commission require AmerenCIPS to sell approximately 90% of the parcel (since AmerenCIPS will not need more than 10% for the Substation) and remove from rate base an amount equivalent to the proceeds from the sale. He adds that AmerenCIPS' cost for the property would be more appropriately included in a future rate case at a time when AmerenCIPS' actual use of the property is known.

c. Commission Conclusion

The issue here is whether AIU adequately demonstrated that its planned Substation will be built and in service on the parcel of land purchased within 10 years of the test year. AIU supplied the Commission with evidence showing that current and anticipated load growth in the area is driving the need for a new bulk supply substation. The Commission believes that AIU's intention to build the Substation is an example of prudent planning that benefits customers. The Commission also finds that AIU's investment in the property is reasonable and the evidence supports a finding that the timing of the acquisition is appropriate.

The Commission does not share Staff's concern that the Substation is not expected to occupy the entire parcel of land. As the Commission sees it, many factors can influence a utility plan for locating and acquiring land for a substation. Such factors include the location and availability of property, as well as the ability to obtain property rights. Although the Commission believes it was reasonable for AIU to purchase the entire tract at issue here, the Commission directs AIU to use its best efforts to utilize or dispose of the remainder of the tract in a manner that best benefits customers. How AIU decides to deal with the remainder of the tract is an issue that can be revisited in future rate cases. The Commission concludes that AmerenCIPS' investment for the planned Substation should be included in rate base and Staff's proposed disallowance is rejected.

4. Security System Installations

a. AIU's Position

AIU argues that it is required, both as a matter of law and as a matter of prudent, safe, and reliable operations, to have effective security systems for its facilities as described in Section 4-101 of the Act. AIU submits that these provisions require it to have on-site safeguards to restrict physical access to critical infrastructure, and for the electric utilities to follow the most current security standards set forth by the North American Electric Reliability Corporation ("NERC"). According to AIU, the security systems that it installed are designed to meet these requirements. Because the security systems represent prudent investment in needed protection of its facilities, AIU argues that it is entitled to have the security investment included in rate base.

In support of its argument, AIU points out that electric transmission lines, substations, gas pipelines, storage fields and other facilities are considered critical energy infrastructure. AIU submits that securing such critical infrastructure is necessary not just to ensure that customers have adequate and reliable service, but also that interconnected facilities of other utilities throughout the region and the country are protected. AIU points out that Staff witness Rockrohr does not compare AIU security systems or their costs to those of non-AIU utilities, nor did he conduct any outside research into, or review publications related to, security systems. AIU notes that Mr. Rockrohr agrees that protection of AIU's critical infrastructure from terrorist attack and criminal activity is necessary, and he further agrees that AIU's customers benefit from measures to protect AIU's facilities. AIU argues that the evidence in this case shows that its security systems are reasonable and necessary to protect its critical infrastructure and other facilities and personnel. AIU submits that Staff‘s lack of a meaningful comparison of other utilities to AIU demonstrates that Staff has no basis to recommend disallowance of security costs.

b. Staff's Position

Staff recommends that the Commission disallow $178,173 from AmerenCILCO‘s proposed rate base, $881,686 from AmerenCIPS‘ proposed rate base, and $417,528 from AmerenIP‘s proposed rate base, which represents installation costs of state-of-the-art security systems at each utility‘s facilities. Staff contends that AIU demonstrated no need for these security systems, considered no alternative systems, and did not even know the ongoing costs associated with utilizing them. Staff argues that the NERC guidelines do not state that each utility must, or even should, install card readers and closed circuit television cameras at all of its facilities. Instead, Staff notes that the NERC guidelines list types of security systems that a utility might consider when evaluating the adequacy of its existing security. In support of its proposal, Staff points out that even though AIU witness Mullenschlader claims the security systems were installed to satisfy the requirements of NERC guidelines, when asked if AmerenCIPS had experienced security issues at the three facilities associated with AmerenCIPS' expenditure of $608,799, Mr. Mullenschlader stated that no specific data was available. After reviewing all the information that AIU provided about the security systems that were installed at facilities within the operating areas of AmerenCILCO, AmerenCIPS, and AmerenIP, Mr. Rockrohr remains unconvinced that the security system investments were prudent and used and useful in providing service to customers. He believes that these security system costs would more appropriately be paid for by the shareholders of each utility than by customers.

c. Commission Conclusion

The Commission agrees that securing AIU's infrastructure is necessary to ensure that customers have adequate and reliable service. The Commission also believes that AIU's security system costs are a prudent investment, that the security systems benefit customers, and that these systems are used and useful in providing service to customers. Contrary to Staff's suggestion, the need for maintaining the security of utility assets has increased dramatically and what may have been considered excessive or state of the art only a few years ago is now necessary and appropriate.

The Commission, however, is concerned that AIU considered no alternatives to the security system it installed. The Commission understands that AIU chose to use the same vendor that it has previously used; however, in the future AIU should undertake an investigation regarding both the need for and the cost of alternative security systems and be able to better document and justify decisions it makes regarding security investments.

5. Cash Working Capital

a. AIU's Position

In its direct case, AIU presented the results of a lead-lag study to quantify the CWC requirements of each of the gas and electric businesses of AIU. AIU states that CWC reflects the amount of funds required to finance the day-to-day operations of AIU. AIU relates that the two most commonly used methodologies by which to determine a company's CWC requirements are referred to as the —Net Lag” and —Gross Lag” methodologies. AIU adds that the CWC requirements for each of the utilities were calculated employing the Net Lag methodology. Ameren Ex. 3.5 shows the calculation of CWC requirements under the Net Lag methodology. If prepared properly, AIU claims the two methodologies should produce identical results. Ameren Exs. 5.7, 5.8, and 5.9 set forth the calculation of AIU's CWC requirements under the Gross Lag methodology. AIU reports that both methodologies yielded the same results.

Staff witness Kahle has suggested six modifications to the CWC requirements proposed by AIU: (1) use of the Gross Lag methodology rather than the Net Lag methodology; (2) inclusion of pass-through taxes in the calculation of the revenue lag with zero lag days; (3) inclusion of capitalized payroll in the level of payroll expenses used to determine AIU's CWC requirements; (4) correction of the expense lead associated with Employee Benefits; (5) reflection of the impact of Transitional Funding Trust Notes ("TFTN") interest expense; and (6) reflection of Staff's proposed levels of operating expenses in the CWC analysis.

AIU agrees with Mr. Kahle's correction of the expense lead associated with Employee Benefits. AIU says the expense lead originally filed contained a cell reference error that needed to be updated to reflect the corrected expense lead days. AIU believes Mr. Kahle has accurately reflected the expense lead as 24.746 days. AIU indicates that adjusting the expense lead for Employee Benefits reduced AIU's CWC requirements by approximately $9,000. AIU says it also accepts Mr. Kahle's treatment of interest expense on TFTN in the CWC analysis.

AIU does not take exception to Mr. Kahle's use of the Gross Lag methodology, if applied correctly. While it accepts the use of the Gross Lag methodology, AIU disagrees with Mr. Kahle's statement that the Net Lag methodology does not consider the amount of cash provided by ratepayers through base rates. AIU insists that the Net Lag methodology presumes that the operating expenses considered in the analysis are the same as the revenues available to pay such operating expenses; therefore, the Net Lag methodology inherently includes the consideration of revenues, but it does not reflect revenues on the exhibit. Staff, AIU claims, continues to have the misperception that only the Gross Lag methodology reflects revenues. AIU asserts that both methodologies reflect revenues but only the Gross Lag methodology actually shows the revenues on the exhibit.

AIU asserts that the revenues used by Mr. Kahle reflect the revenue requirement which Staff believes to be necessary to earn a fair return on AIU's assets and to pay its operating expenses. From this amount, under the Gross Lag methodology, AIU says the return on equity and all non-cash operating expenses are removed from the operating revenues. The residual revenues included in the CWC analyses under the Gross Lag methodology, AIU states, are the amount required to pay cash operating expenses.

AIU says the objective of the CWC analyses is to evaluate the timing differences between the receipt of revenues and payment of expenses. To accurately determine the CWC requirements, AIU insists that the revenues considered in the analyses must correspond to the expenses and vice versa. AIU asserts that the inclusion of expenses for which there is no corresponding revenue stream will produce results which do not reflect the true CWC requirements of AIU. When employing the Gross Lag methodology, AIU says it is important to maintain a balance between the level of revenues and operating expenses considered in the analyses. AIU states that the level of revenues considered in the analyses should reflect only those funds which are available to pay actual cash operating expenses. AIU says a number of reductions are made from actual revenues to arrive at the amount which is truly available to pay actual operating expenses. Similarly, AIU claims the operating expenses considered in the CWC analyses should only include those operating expenses for which there is a corresponding revenue stream.

AIU claims that its application of the Gross Lag methodology maintains the balance between revenues and operating expenses because the revenues and operating expenses considered in the CWC analyses are equal. AIU asserts that the analyses set forth by Mr. Kahle, however, does not maintain the balance between revenues and operating expenses. According to AIU, Mr. Kahle inappropriately makes changes to the level of operating expenses (e.g., capitalized items) without a corresponding change to the revenue side of the equation. Under Mr. Kahle‘s approach, AIU claims the operating expenses have been artificially inflated thereby erroneously reducing AIU's CWC requirements.

AIU takes exception to Mr. Kahle‘s proposed treatment of pass-through taxes in calculating CWC requirements. Mr. Kahle proposes to include pass-through taxes in the CWC analyses, but to reflect a revenue lag associated with these taxes of zero days. AIU says Mr. Kahle assigns an expense lead of 42.79 days for the pass-through taxes. AIU claims the reduction of AIU's CWC requirements based upon Mr. Kahle‘s proposed adjustment to pass-through taxes is approximately $7 million.

According to AIU, Mr. Kahle‘s proposed treatment of pass-through taxes should be rejected because it has no foundation in reality. AIU says the revenue lag consists of five components; (1) a service lag; (2) a billing lag; (3) a collections lag; (4) a payment processing lag; and (5) a bank float lag. Collectively, AIU claims these components add up to the 40.95 days of revenue lag utilized by both Staff and AIU for purposes of determining AIU's CWC requirements. AIU states that the expense lead consists of three components; (1) a service lead; (2) a payment lead; and (3) a bank float lead. The expense lead used by both Staff and AIU was determined to be 42.79 days.

In AIU's view, it is appropriate to include pass-through taxes in the CWC analyses because there is a slight timing difference between AIU's receipt of payment from customers and the remittance of the taxes to the proper taxing authority. By including the pass-through taxes in the CWC analyses, AIU claims it is reflecting the benefit of having access to the funds from the time of receipt to the time of remittance.

According to AIU, Mr. Kahle‘s position is based on the incorrect premise that AIU has access to the funds associated with the pass-through taxes for 42.79 days. AIU contends that it collect the funds associated with the pass-through taxes when the customers pay their bills. AIU maintains that there is no separate source of funds provided by the customers associated with the pass-through taxes.

Mr. Kahle, AIU avers, appears to suggest that there is no service lag associated with the pass-through taxes. AIU says that while that may be a reasonable position, there can not be a service lead on the expense side of the CWC calculation if there is no service lag on the revenue side of the equation. AIU claims Mr. Kahle's rebuttal position acknowledges this fact. Despite this modification, AIU asserts that Mr. Kahle's position continues to be flawed because it fails to reflect the true timing of cash receipts versus cash outlays. Despite Mr. Kahle's assertion to the contrary, AIU insists it does not have access to the funds attributable to the pass-through taxes during those days and claims that Mr. Kahle has provided no evidence to the contrary.

AIU also disputes Staff's assertion that pass-through taxes are not revenue. According to AIU, pass-through taxes are included in both revenues and expenses in the test year, before pro forma adjustments. AIU argues that it has provided service to customers, giving rise to the cost associated with pass-through taxes, and have to collect such monies from customers. Without the provision of service, AIU says there are no pass-through taxes.

If the Commission were to determine that there was no service lag/lead associated with the pass-through taxes, AIU says a revenue lag of 25.74 days should be applied to the appropriate level of revenues attributable to pass-through taxes and an expense lead of 27.58 days (i.e., 42.79 minus 15.21 days) should be applied to the expense levels associated with pass-through taxes. AIU states that this change would result in no change to AIU's CWC requirements. AIU also claims that the Commission previously declined to adopt the position proposed by Mr. Kahle. (AIU Initial Brief at 79-80, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 22)

AIU also takes exception to Mr. Kahle's proposed inclusion of capitalized payroll expenditures in the operating expenses used to calculate the CWC requirements. AIU indicates that Mr. Kahle proposes to include capitalized payroll in the CWC analyses by adding the amount of capitalized payroll to the operating expenses without a corresponding revenue stream. According to AIU, the impact of Mr. Kahle's proposed inclusion of capitalized payroll in the CWC analyses is to reduce AIU's CWC requirements by approximately $3 million.

Mr. Kahle, AIU states, tries to justify the use of this limited number of capitalized items in the calculation of the CWC requirements on the grounds that the Commission accepted a similar position in the last electric rate proceedings for AIU (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 36). AIU contends that Mr. Kahle, however, has provided no independent justification or rationale for the inclusion of the capitalized items in the CWC analyses, and, asserts that they should not be included at all.

AIU argues that Mr. Kahle has artificially created an imbalance by including in his analyses expenses for which there is no corresponding revenues, thereby resulting in a lower CWC requirement which is not indicative of the true CWC needs. AIU claims Mr. Kahle‘s inclusion of these capitalized costs is also inappropriate because his analyses represent only a partial view of capitalized expenditures. AIU claims it incurs significant levels of expenditures on an annual basis associated with capital programs and initiatives. AIU says Mr. Kahle‘s proposed treatment of capital expenditures does not reflect all of the capital expenditures and that he is selective in what items to include. Further, AIU asserts that Mr. Kahle has reflected an expenditure with significant dollars and relatively short expense lead time, artificially deflating the CWC requirements of AIU. In AIU‘s view, Staff‘s analyses reflect an incomplete view of capitalized expenditures and an artificially created imbalance between the revenues and operating expenses.

AIU says it has not included all of the capitalized expenditures in its CWC analyses. AIU claims its analyses reflect the actual cash operating expenses incurred during the test year. The capitalized amounts, AIU argues, are appropriately included in rate base and thus earn a return on such investments. AIU insists that it is inappropriate to include the capitalized expenditures in the CWC analyses. Regardless, AIU contends it would be inappropriate to include only a portion of the capitalized expenditures and only on one side of the revenue and expense equation. AIU maintains that the revenues which Mr. Kahle uses reflect the revenue requirement for the AIU. From those revenues, AIU says he appropriately subtracts non-cash expenses and return on equity. The residual revenues, AIU states, are those dollars which are available to pay cash operating expenses. AIU claims there are no incremental dollars in the analyses to account for the capitalized expenditures which Mr. Kahle proposes to include in the analyses. AIU concludes that Mr. Kahle has artificially created an imbalance between the levels of revenues and expenses considered in the analyses.

AIU is aware of only one solution that could remedy that imbalance: include in the CWC analyses a separate revenue stream relating to the amount of capitalized payroll. AIU says the revenue lag for this revenue stream would have to be the composite years over which AIU's assets are depreciated. AIU states that Mr. Adams, however, did not perform such a calculation because he does not agree with the inclusion of the capitalized expenditures in the CWC analyses. AIU, therefore, does not believe that an alternative to address Mr. Kahle‘s flawed recommendation is warranted.

Mr. Kahle believes it is appropriate to include the capitalized payroll in the CWC analyses because the test year is a historical test year and no portion of payroll after the effective date of the new rates is included in the rate base. AIU disagrees because the test year reflects a full twelve months of wages, reflected for known and measurable changes. AIU asserts that there is no need to reflect some level of payroll after the effective date of the new rates. AIU says Staff has not adjusted the expense level of wages to address this concern of Mr. Kahle‘s. AIU therefore concludes that there is no need to make such an adjustment for the CWC analyses.

AIU says it is true that it has not included capitalized payroll for the calendar year 2009 and claims it would be inappropriate to do so without a known and measurable capital adjustment with which the capitalized payroll is associated. According to AIU, Mr. Kahle's adjustment reaches beyond the 2006 test year to include 2009 capitalized payroll, which he assumes will be incurred at the 2006 historical level, and includes the presumed capitalized expenditure in an historical test year. AIU asserts that Staff has provided no evidence that the level of capitalized payroll in 2009 will be the same as it was in 2006. AIU says its level of capitalized payroll varies on an annual basis. Once the actual capitalized expenditures are incurred, AIU claims they will be reflected in AIU's rate base in the next rate proceeding. AIU insists that it would be inappropriate to include an unsubstantiated level of future capitalized payroll in these proceedings. AIU also disagrees with Staff that its proposal correctly reflects cash needs, since Staff has not provided a source of cash for the capitalized payroll cash outlay. If the Commission decides to include the capitalized expenditures, AIU maintains that a revenue stream must also be included in the CWC analyses.

AIU says that in rebuttal, Mr. Kahle argues that AIU witness Adams is wrong in asserting that a balance between revenue and expense level is required because the Commission's order in AIU's prior rate proceedings included adjustments to CWC which were based on analyses in which expenses were greater than revenues. AIU states that Mr. Kahle also argues that the inclusion of the capitalized portion of payroll expense in determining CWC requirements does not affect AIU's recovery of payroll costs.

According to AIU, Mr. Kahle's argument for his treatment of capitalized expenditures is based exclusively on the Commission's decision in AIU's last electric cases. AIU says it does not believe that a mistake should be repeated merely based upon past mistakes. AIU believes the appropriateness of the proposed adjustment should be evaluated based upon the merit of the arguments in the proceeding and not merely upon a prior Commission ruling. AIU maintains that Mr. Kahle's proposed adjustment is flawed, does not reflect the true CWC requirements of AIU, and should be rejected.

To the extent Commission precedent guides the Commission in this proceeding, AIU urges the Commission to focus on Docket Nos. 07-0241/0242 (Cons.). In that more recent proceeding, AIU says the Commission reversed its decision on this issue. AIU claims that Mr. Kahle dismisses that decision by claiming that the circumstances were different. In AIU's view, the circumstances in the two cases are not different; only the result was different and did not favor Staff's proposed adjustment.

Mr. Kahle has also proposed an adjustment to the CWC component of Rider PER - Purchased Electricity Recovery ("Rider PER"). AIU indicates that Mr. Kahle's calculation uses 23.94 expense lead days instead of the 18.15 days AIU proposes to use. AIU states that Mr. Kahle believes since AIU and Ameren Energy Marketing Company are affiliates, it is not reasonable to apply the shortened service period and advanced payment time to their transactions. AIU asserts that its current credit ranking has shortened the service period for purchased power to a half-month with payments due on the first business day nine days following the end of the service period. AIU says Mr. Kahle does not contest the application of the shortened payment periods for non-affiliated companies, but proposes to disallow the shortened payment period for affiliated companies. Mr. Kahle contends that the shortened payment period does not apply to the affiliated companies because the funds for these purchases come from and end-up in the same pool of money.

Based upon Mr. Kahle's proposed adjustment, AIU says it appears that he believes that the dealings with affiliates should be handled differently than those with non-affiliated companies. Citing 83 Ill. Code 450, "Non-Discrimination in Affiliate Transactions for Electric Utilities" ("Part 450"), AIU claims the Commission's rules pertaining to transactions with affiliated marketing companies strictly forbid such unique treatment. AIU believes that providing payment terms which are different than those encountered between AIU and non-affiliated marketing companies would be contrary to the Commission's rules. AIU also argues that it and Ameren's marketing affiliates do not commingle funds as suggested by Mr. Kahle. AIU says each business operates as a stand-alone company and is responsible for its own financial transactions. AIU also claims that the source of the funds has no relevance on the timing of payment for transactions. The CWC component of Rider PER, AIU asserts, should reflect the actual timing of cash receipts and cash payments, not Mr. Kahle's assumed preferential treatment afforded to an affiliated marketing company.

AIU says that in rebuttal, Mr. Kahle argues that using the shortened service period for AIU's purchases from affiliates does not run afoul of Part 450 because it only prohibits preferential treatment, and his proposal does not provide preferential treatment. According to AIU, Mr. Kahle also argues that although AIU and Ameren Energy Marketing Company do not commingle funds, it is not logical that Ameren Energy Marketing Company would refuse to keep AIU as a customer if its payments were not advanced as allowed under the Supplier Forward Contracts.

According to AIU, the Commission has rules in place to protect against preferential treatment between affiliated companies. AIU claims Mr. Kahle is essentially proposing to bypass such safeguards. AIU asserts that Mr. Kahle makes an unsubstantiated assumption that the affiliated suppliers would even be willing to provide different payment terms for AIU. AIU contends that the non-affiliated providers could also choose to not seek advanced payments, but they did not. AIU believes it is unreasonable to assume that the affiliated providers would be more willing to waive the accelerated payments and assume additional risk without compensation. In AIU's view, these are the types of situations which the Commission's affiliate rules are intended to prevent. AIU concludes that Mr. Kahle's proposed adjustment to the CWC component of Rider PER should be rejected.

b. Staff's Position

Mr. Kahle proposes downward adjustments to the level of CWC to be included in rate base by the following amounts: $645,000 for AmerenIP's gas operations,

$1,563,000 for AmerenIP's electric operations, $668,000 for AmerenCIPS' gas operations, $1,060,000 for AmerenCIPS' electric operations, and $72,000 for AmerenCILCO's electric. He proposes an increase of $151,000 for AmerenCILCO's gas operations. To calculate his proposed CWC for AIU, Mr. Kahle proposes adjusting the lead days for Employee Benefits to 24.746 days due to an error in AIU's lead/lag workpapers related to Group Health Administration lead days. Staff indicates that AIU accepts Staff's adjustment for each of the utilities.

Mr. Kahle also proposes that the Gross Lag methodology be used in calculating CWC. AIU indicates that it is willing to accept the use of the Gross Lag methodology as long as the methodology is applied properly. Thus, Staff reports that the following CWC items are in dispute: capitalized payroll in CWC requirements; applying zero revenue lag days to pass-through taxes; and expense levels to which CWC factors are applied.

Mr. Kahle proposes to include total payroll in the CWC requirements, including the amounts capitalized as well as those charged directly to expense accounts in the CWC calculation, since all require cash. AIU argues that capitalized items are appropriately included in rate base, not in the CWC analyses. Staff contends, however, that capitalized payroll included in rate base does not include any payroll costs going forward. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding.

Staff asserts that processing and paying payroll is part of the AIU's day-to-day operations, that payroll to be paid in January 2009 is not in rate base in this proceeding and is outside the test year, and that AIU requires cash to meet its payroll in January of 2009. According to Staff, the circumstances in this proceeding are similar to the previous AIU rate case proceeding in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), in which the Commission found that the capitalized portion of payroll should be included in the CWC calculation. Staff believes that its proposal, which uses total base payroll in the CWC requirement calculation, correctly reflects cash needs of AIU and should be approved by the Commission rather than AIU's proposal which only considers payroll costs charged directly to salary and wages expense accounts.

In its Reply Brief, Staff claims AIU attempts to confuse the issue by implying that capitalized expenditures should not be included in the CWC requirement calculation because capitalized expenditures are included in rate base. Staff argues that expenditures, whether expensed or capitalized, are not, in themselves, recovered by adding the CWC requirement to rate base. Staff claims that only the financing of the expenditure is recovered by adding capitalized items to rate base. According to Staff, CWC is the amount of funds required from investors to finance the day-to-day operations of AIU. Adding CWC to rate base, Staff states, allows the investors to recover the time-value-of money associated with the cash outlay. Staff submits that including the capitalized portion of payroll expense in determining the CWC requirements only affects the amount of CWC requirement added to rate base for financing day-to-day operations of AIU, and does not affect the recovery of payroll expense itself. Staff says AIU also advances an argument that revenues and expenses in the CWC requirement calculation must be equal. Staff contends this is not the case since the Commission has adopted CWC requirement calculations in which revenues and expenses are not equal. (Staff Reply Brief at 38-39, citing Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Appendix A, B and C at 6; Docket Nos. 07-0241/07-0242 (Cons.), Appendix A at 10 and Appendix B at 9) Staff also claims that in previous AIU rate proceedings, AIU has filed CWC requirement calculations in which revenues and expenses are not equal for AmerenCIPS gas and AmerenUE.

Mr. Kahle proposes to apply revenue lag days of zero to pass-through taxes. According to Staff, there is no revenue lag associated with pass-through taxes since pass-through taxes are not revenue. Staff asserts that AIU provided no service and did nothing to earn pass-through taxes. Staff claims investors have provided no investment related to the collection of pass-through taxes other than for operation and maintenance expenses already included elsewhere in the CWC calculation. Pass-through taxes, Staff says, are added on to the ratepayers' bills and then remitted to the appropriate taxing body. Staff contends that including a revenue lag for pass-through taxes in the CWC calculation would increase AIU's CWC requirement, and thereby increase rate base, allowing investors to earn a return on ratepayer supplied funding.

Staff states that ratepayers provide pass-through taxes for a taxing body with AIU having the use of these funds until AIU remits the taxes to the appropriate taxing body. Energy Assistance Charges, Staff states, are paid monthly by AIU on the 20th day following the month. AIU has use of these ratepayer provided funds from the time they are collected until the 20th of the following month plus bank float time, according to Staff. Gross Receipt Taxes, Staff adds, are paid monthly by AIU in the month following the month for which they are due. Staff says AIU has use of these ratepayer provided funds from the time they are collected until they are paid in the following month. Staff concludes that its proposal to use zero days for revenue lag correctly reflects that AIU has no cash requirements necessary to collect and remit pass-through taxes.

Mr. Kahle also proposes an adjustment to the CWC component of Rider PER to use 23.94 expense lead days instead of the 18.15 days that AIU proposes to use. AIU claims that Staff's logic is flawed and that it is reasonable to apply a shortened service period and advanced payment time in the transactions between AIU and Ameren Energy Marketing Company. Staff asserts that while AIU is referring to the affiliates' payment terms, Staff is referring to the calculation of the CWC component of Rider PER. Staff argues that its calculation affects Rider PER but not the actual power purchases from affiliates. Staff contends that using a greater number of expense lead days for the CWC component of Rider PER, which causes AIU to have a lower CWC requirement for purchased power, is not preferential treatment of an affiliate.

c. The AG's and CUB's Position

In addition to the CWC requirements based on the lead-lag studies, CUB says AIU increased the electric rate bases for each utility by an additional CWC allowance to reflect a material increase in accounts receivable being experienced by AIU since the 2006 test year. According to CUB, the additional CWC increases the AmerenCILCO electric rate base by $3,478,000, the AmerenCIPS electric rate base by $6,406,000, and the AmerenIP electric rate base by $10,116,000. CUB says the increase applicable to each individual utility was calculated by allocating the total requested increase of $20 million in accounts receivable among the three utilities based on the number of electric distribution customers of each of the utilities. The $20 million total, CUB states, is based on an observed increase in the balance of accounts receivable in September 2007 over the level in prior years.

In CUB's view, there are several problems with the additional CWC increases proposed by AIU. CUB argues that AIU has not established that the observed increase in 2007 is permanent in nature. CUB also contends that an increase in accounts receivable by itself does not establish an increase in the CWC requirement. The CWC requirement, CUB says, is calculated as the cash needed to bridge the gap between the payment of expenses and the receipt of cash from customers to cover those expenses. To the extent that the increase in accounts receivable is the result of an increase in expenses, CUB claims the increase in receivables could well be matched by an increase in payables, resulting in no net increase to the CWC requirement. Based upon these concerns, AG/CUB witness Effron proposes that the additional CWC related to the increase in accounts receivable in 2007 be eliminated from AIU's electric rate bases.

d. Commission Conclusion

With regard to calculating CWC, the only remaining contested issues between Staff and AIU are whether capitalized payroll should be included in CWC requirements and whether it is appropriate to apply zero revenue lag days to pass-through taxes . The AG/CUB as well as Staff propose eliminating the additional CWC requirement associated with increased accounts receivable in 2007. In its rebuttal testimony, for purposes of the instant proceeding, AIU withdrew its proposal to increase CWC to reflect higher accounts receivable in 2007; thus, this issue is no longer contested. Finally, the Commission‘s review of AIU‘s and Staff‘s Briefs on Exceptions and their Briefs in Reply to Exceptions reveals that the Proposed Order failed to include a conclusion regarding whether the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU should be adjusted as Staff proposed. It appears the Proposed Order failed to reach a conclusion on this issue, in part, because Staff treated this as a contested rate base issue while AIU treated it as a resolved electric rate design/tariff issue. In any event, this issue will be addressed in this portion of the Order.

As the Commission understands it, Staff proposes to include capitalized payroll, as well as payroll expense, in the CWC calculation since Staff believes both types of payroll payments require cash. Staff believes the CWC necessary to cover payroll capitalized on an on-going basis when the rates from this proceeding go into effect are not included in rate base in this proceeding. Alternatively, AIU argues that capitalized items are appropriately included in rate base and not in the CWC analyses.

The Commission has reviewed the arguments of the parties as well as the previous decisions cited by the parties. Utilities acquire cash when ratepayers pay bills as well as through the issuance of debt and equity. The sources and uses of cash are comingled and can not be distinguished. The purpose of estimating a CWC requirement is to determine the level of funds required to meet a utility's day-to-day operations. By including CWC in rate base, the Commission allows a utility the opportunity to recover the cost of raising cash from its investors that is used in day to day operations. Capitalized costs, which are all paid with cash, are included in rate base so that a utility has an opportunity to recover the cost of financing that capital requirement item over time. In the Commission's view, if any capitalized cost, including capitalized payroll costs, were also reflected in the CWC balance, it would effectively be included in rate base twice. While it is true that cash is required to meet the requirements for payroll costs that are capitalized, the same is true for every other expense that is capitalized and the Commission can not understand the basis for singling out capitalized payroll costs. As a result, the Commission rejects Staff‘s proposed treatment of capitalized payroll costs when estimating the CWC requirement.

The Commission recognizes that Staff's proposed adjustment is consistent with the Order in the last AIU rate case; however, a review of that Order suggests AIU's failure to properly brief the issue in that case did little to help its position. Additionally, the Commission notes that the decision herein is consistent with the more recent decision in Docket Nos. 07-0241/07-0242 (Cons.), and believes the decision here is consistent with the record of this proceeding.

With respect to pass-through taxes, Staff proposes to apply zero revenue lag days arguing: that pass-through taxes are not revenue; that AIU provides no service and did nothing to earn pass-through taxes; and investors have provided no investment related to the collection of pass-through taxes. AIU believes pass-through taxes should be reflected in the CWC analysis due to the slight timing difference between AIU's receipt of payment and the remittance of tax revenue.

The Commission reviewed the arguments and, in the context of a CWC requirement, is unable to discern a meaningful difference between pass-through taxes and most other expenses. Customers pay their bills, including pass-through taxes, providing AIU with cash. AIU makes cash payments, including pass-through taxes, to those entities that have a rightful claim. Again, in the context of CWC requirement, pass-through taxes are no different than State or Federal income taxes or employee payroll expense. The Commission therefore concludes that Staff‘s proposed adjustment to the CWC requirement associated with pass-through taxes is inappropriate and is hereby rejected.

Staff proposes to adjust the expense lead days associated with purchase power transactions between Ameren Energy Marketing Company and AIU, but not the expense lead days between unaffiliated suppliers and AIU. Under Staff's proposal, Ameren Energy Marketing Company would be treated differently than unaffiliated power and energy providers. These transactions are governed by supply contracts previously approved by the Commission, and the Commission finds Staff's proposal is inconsistent with the intent that all power and energy providers are to be treated the same. Staff's argument that it is simply proposing an adjustment to lower the CWC requirement but not the actual power purchases from Ameren Energy Marketing Company misses the point. This proposal would effectively deny AIU the opportunity to recover costs associated with supply contracts AIU entered into under Commission oversight. Such a proposal is not reasonable and is therefore rejected.

6. Physical Losses and Performance Variations

This issue concerns Accounts 352.3, "Nonrecoverable natural gas," and 823, "Gas losses," of the USOA for Gas Utilities. Account 352.3 provides in relevant part:

> A. This account shall include the cost of gas in underground reservoirs, including depleted gas or oil fields and other underground caverns or reservoirs used for the storage of gas which will not be recoverable.

Account 823 states in its entirety:

> This Account shall include the amounts of inventory adjustments representing the cost of gas lost or unaccounted for in underground storage operations due to cumulative inaccuracies of gas measurements or other causes. (See Paragraph G of Account 117, Gas stored underground – Noncurrent.) If however, any adjustment is substantial, the utility may, with approval of the Commission, amortize the amount of the adjustment to this Account over future operating periods.

a. Staff's Position

According to Staff witness Anderson, AIU's gas utilities attempt to treat every instance associated with storage field adjustments in the same manner, while there are actually distinctions in the types of storage adjustments. Mr. Anderson states that AIU's gas utilities are experiencing two different types of storage adjustments: physical losses and underground storage performance variations. Staff says physical losses refer to a known gas loss that can be attributed to a specific event at the storage field and occur as a result of the normal operation and maintenance of the storage field or even as a result of a leak within the storage field itself. Staff claims that underground storage field performance variation refers to changes in the storage field inventory, resulting in the need to add or subtract from the inventory at a storage field, which can not be attributed to a specific physical incident. Underground storage field performance variations, Staff states, are normally detected after an engineering evaluation by the deterioration of the performance of an underground storage field.

While not necessarily agreeing with Staff's delineation of underground storage adjustments into two categories, Staff says AIU does not dispute Staff's explanation or description of the two categories. Instead, Staff says AIU maintains that both types of underground storage adjustments should be recorded in Account 823. In contrast, Staff witness Everson argues that performance variations are more properly recorded in Account 352.3 (rate base), and physical losses in Account 823 (expense). According to Staff, the contested issue here is the proper accounting treatment for AIU's performance variations.

Staff claims its proposal to place performance variations in Account 352.3 involves the basic mechanics associated with operating a storage field and that the majority of the performance variations result from gas migration. Specifically, Mr. Anderson states that natural gas is injected into an aquifer storage field above the pressure of the water in the aquifer. He says the natural gas injected will expand until the gas pressure and the water pressure reach equilibrium if there are no additional injections or withdrawals and a steady state is allowed to exist. In most aquifer storage fields, Staff says normal operation usually results in an average gas pressure above the aquifer pressure in the storage reservoir. As a result, Staff claims a small portion of the working or top gas tends to migrate to non-recoverable base gas over time, causing underground storage field inventory variations.

Mr. Anderson states that when gas is removed during the storage field's withdrawal cycle, the gas pressure within the field declines, allowing water to return to areas that had previously contained gas. According to Staff, each year, a utility injects gas that moves the water out, but the water returns when the utility withdraws the gas. Staff contends that because of this cycling of the storage field, a portion of the field's inventory also tends to migrate from working or top inventory to non-recoverable base gas.

AIU asserts that there are three major factors requiring the need for a utility to add gas to a storage field: (1) errors introduced over long periods of time through engineering calculations, (2) numerous gas losses that occur that are not estimated because they are unknown or are of a small magnitude, and (3) accumulated clerical and accounting errors, metering inaccuracies, and other operational/maintenance losses are the. Staff states that neither it nor AIU has been able to identify a method to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base gas.

Staff believes that AIU accuses it of ignoring AIU's evaluation that uses the Tek Methodology, which AIU claims demonstrates that physical losses are occurring. The Tek Methodology is a gas loss calculation methodology presented in Appendix I of M. R. Tek's textbook, ―Underground Storage of Natural Gas–Complete Design and Operational Procedures" (―Tek Methodology"). Staff says it is not ignoring AIU's evaluation; instead, Staff claims it is attempting to clarify AIU's analysis. Staff also disputes AIU's assertion that migration is not the major factor in the cause of or the need for performance variation adjustments. While Staff does not dispute that the three factors AIU identified can contribute, Staff argues that common sense suggests these are not the major factors causing performance variations.

Regarding the first factor, errors introduced over long periods of time, Staff states that since 2005 AIU has been making annual or nearly annual adjustments to all of its storage fields' inventory volumes. Staff also indicates that AmerenCILCO has made storage inventory adjustments since at least 1996, and passed those costs on to ratepayers. In Staff's view, there should not be any long-term accumulation of errors given the frequency with which the AIU makes storage adjustments.

Regarding the second factor, gas losses that occur that are not estimated because they are unknown or of small magnitude, Staff says that AmerenCIPS recorded physical losses as small as 136 million cubic feet (―Mcf") during the test year, while AmerenIP recorded losses as small as 26 Mcf. Staff argues that comparing the volumes of these physical losses, which AIU takes the time to identify and estimate to the magnitude of the annual adjustments (20,000-40,000 Mcf for AmerenCIPS; 3,445-228,102 Mcf for AmerenIP), demonstrates that any amounts that are too small for AIU to identify or estimate should be significantly less than the volumes AIU assigns to performance variations.

Regarding the third factor, accumulated clerical/accounting errors, metering inaccuracies, and other operational/maintenance losses, Staff asserts that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff claims that meter accuracies are provided in a +/- 0.5 to 1% range. According to Staff, this means that metering could contribute or even reduce or create a negative loss of gas. Staff adds that AIU indicated, for at least its Hillsboro Storage Field metering, that its metering uncertainty is much less or about 0.25%. This demonstrates, Staff argues, that AIU has the means to reduce metering uncertainty. Staff believes metering errors should not be a major contributor to performance variations. Regarding other operational or maintenance losses, Staff maintains that AIU identifies and estimates fairly small gas losses and adds that AIU makes frequent annual inventory adjustments.

Staff argues that in a well-managed underground storage field operation, engineering estimates of physical gas losses should be reasonably accurate, unknown physical losses should be small, and metering errors should be determined and corrected as part of routine maintenance. Staff also contends that clerical/accounting errors should be found and corrected if adequate controls are in place. Staff says AIU has not demonstrated that any of these potential losses are significant or that the volumes associated with them would cause performance variations.

Staff claims that the need to significantly increase the non-recoverable base gas at AmerenCIPS' Sciota storage field is an indication that gas has been migrating on a regular basis in prior years. According to Staff, this is in direct contrast to AIU's position that all the annual adjustments at issue in this case are due to gas that has physically left the storage fields, and that migration is not causing these adjustments or migration is not occurring.

According to Staff, AIU complains about this being the first proceeding where it has been confronted with the concept of performance variations, and thus, has not had the opportunity to fully analyze the issue. However, Staff states that in Docket No. 02-0717, AmerenCILCO's 2002 purchased gas adjustment ("PGA") proceeding, not only did the Commission place AmerenCILCO on notice that at the earliest time possible it should treat and recover those storage adjustments as base rates, but Staff also indicated the proper accounting treatment would either be Account 352.3 or Account 823. (Staff Initial Brief at 75-76, citing Docket No. 02-0717, Order at 5) Staff also states that in Docket No. 03-0696, AmerenCIPS' 2003 PGA proceeding, wherein AmerenCIPS attempted to recover storage adjustments through the PGA, the Commission indicated that the costs in question are recoverable through base rates either through Account 352.3 or Account 823. (Id., citing Docket No. 03-0696, Order at 5) Despite AIU's protests in the instant proceeding, Staff claims the appropriate accounting treatment for its storage adjustments has been a concern between AIU and the Commission for some time.

AIU asserts that the amounts stated in the accounting of the losses should match the physical inventory amounts in the field. AIU is concerned that if the losses are continued to be accounted for as unrecoverable cushion gas, then the accounting numbers will eventually exceed what the field could physically hold as unrecoverable cushion gas. Staff contends that this is true only if AIU's view of how performance variations occur or what they represent is valid. Staff adds that if the accounting losses exceed what the field could physically hold as unrecoverable cushion gas, then AIU, after the appropriate engineering analysis, would have reason to request an alteration of how it accounts for its performance variations.

AIU cites the Order in Docket No. 04-0779, wherein the Commission allowed Nicor to recover in base rates costs that it had been recovering through its PGA clause as an operating expense. AIU claims that the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823. Staff, however, suggests it is unclear whether AIU's situation is the same as Nicor's based on the language in the Order in Docket No. 04-0779.

Staff states that in Docket Nos. 07-0241/07-0242 (Cons.), Peoples used 3.5% of injected volumes as additional base gas (base gas is accounted for in Account 352.3) to support Manlove Storage Field's performance. According to Staff, the Peoples witness stated that the gas in the Manlove reservoir is under pressure and tends to expand, radially invading new areas, and when this occurs some of the gas is inevitably trapped as cushion gas. (Staff Initial Brief at 77, citing Docket Nos. 07-0241/07-0242 (Cons.), Order at 105-106) Staff believes the discussion in the North Shore/Peoples Order supports Mr. Anderson's testimony regarding the existence and role of gas migration in performance variations.

Ms. Everson calculates an adjustment to reflect the proper accounting treatment of gas losses based on Mr. Anderson's testimony regarding the nature of the gas losses experienced by AIU. Staff states that losses that are not attributable to a specific cause or incident can be characterized as storage field performance variations, and this gas, which is not expected to be recovered, should be classified as ―non-recoverable base gas" and recorded in Account 352.3. According to Staff, Account 352.3 represents non-recoverable gas that can not be physically recovered when the field is abandoned and, therefore, amounts related to this gas loss should be capitalized and depreciated. Staff reports that none of the AIU gas utilities recorded losses in Account 352.3 from 1997 through 2006. Staff asserts that some of the variations AIU recorded in Account 823 were field performance variations and should be classified as non-recoverable gas and recorded in Account 352.3.

Ms. Everson also recommends that future gas losses should be recorded based on the nature of the loss. She says physical losses should be expensed in the period incurred in Account 823, while adjustments for underground storage field performance variations should be recorded in Account 352.3 and subject to depreciation. AIU responds that to properly adjust in this manner, gas losses identified as performance variations in other years would need to be adjusted from Account 823 to Account 352.3, and that such an adjustment would need to be made for performance variations that occurred within the last 10 years.

In response, Staff indicates that the adjustment to reclassify a portion of the 2006 test year cost of gas storage losses from Account 823 to Account 352.3 does not change their recoverability, only the manner in which they are recovered. Furthermore, Staff disagrees that amounts recorded to Account 823 in the past 10 years would have to be reclassified. Ms. Everson states that these adjustments will not require any other adjustments be made, to either the current rate case's rate base or AIU's books, for gas storage losses charged incorrectly to Account 823 in prior years. Staff says the gas storage losses from prior years have already been recovered by AIU through the rates charged during those years. According to Staff, to now reclassify and include those amounts in Account 352.3 would result in double-recovery, since the ratepayer has already paid for these costs through prior years' charges. In Staff's view, while the costs of prior years' performance variations should have been charged to Account 352.3 as well, the fact is they were not. Instead, Staff claims they have been completely recovered through the rates charged to ratepayers during those years, thus making the manner in which they should be recovered a moot issue.

Staff says that in surrebuttal testimony, AIU agrees that no reclassification of prior years' costs associated with AmerenCILCO's storage fields would be necessary. AIU maintains that a reclassification is needed for the prior years' costs associated with AmerenCIPS' and AmerenIP's storage fields. The basis for this assertion is that the amounts included in AmerenCIPS' and AmerenIP's last rate case for Account 823 expenses are not adequate to cover the charges made to this account in subsequent years. Staff believes AIU's reasoning is without merit. Staff argues that in the years between rate cases, the actual charges incurred for any expense has the potential to be less than or greater than the amount that was included for that expense in the last rate case. Staff describes this situation as regulatory lag. Staff claims such differences are not allowed to be considered in rate cases establishing the revenue requirement for future periods. Assuming such a situation did exist with respect to Account 823 charges, Staff contends it was known by AIU at the time of the initial rate case filing and yet AIU made no attempt to include the shortfall in its revenue requests. Staff asserts that such actions would constitute retroactive ratemaking.

In its Reply Brief, Staff disputes AIU's suggestion that what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas unaccounted for in underground storage operations due to other causes. Staff argues that if all storage adjustments, regardless of nature, could be properly recorded to Account 823, there would be no need for Account 352.3 to have ever been included in the Chart of Accounts. According to Staff, the reason why both Account 352.3 and Account 823 are necessary is to recognize the accounting difference between capital and expense items. Staff says Account 352.3 is a capital account and Account 823 is an expense account. Staff maintains that non-recoverable base gas is a capital cost. Staff insists that it would be a violation of accounting theory to charge such costs to an expense account as AIU advocates.

Staff also takes issue with AIU's statement that at the time of the last rate case these costs were not included in the base rates and therefore have not been collected. Staff says this statement refers to AmerenCILCO's storage field adjustments. According to Staff, the costs at issue here have been completely recovered through AmerenCILCO's PGA and, therefore, were not included in the base rates in AmerenCILCO's last rate case. To have done so, Staff argues, would have resulted in double recovery; first through base rates and then again in the PGA.

AIU points out that the AmerenCILCO's 2005-2007 PGA reconciliations are still pending a final Commission Order. Staff claims that, while this is technically true, AmerenCILCO has already recovered the costs for these years and would only have to return any amounts it collected for costs that may be deemed imprudent. (Staff Reply Brief at 46, citing 83 Ill. Adm. Code 525.70(b)) Staff says such an imprudence finding would still make AIU's reclassification argument moot since any costs found to be imprudent would not be allowed to be recovered through base rates either.

Staff argues that because there is no method for allocating between physical losses and migrating gas, the total amounts of performance variation adjustments must be charged entirely to either Account 352.3 or Account 823. Staff claims the costs can not be allocated even though they might contain elements of both physical losses and non-recoverable base gas. Staff asserts that as a result, neither account will be the perfect fit. The goal, in Staff's view, must be to use the account that most accurately reflects the true nature of the performance variations. Staff contends that this is Account 352.3 based on: (1) Mr. Anderson's arguments that the majority of performance variations are the result of gas that has migrated to non-recoverable base gas; (2) AIU's annual storage field inventory adjustments that reduce cumulative losses from inaccurate metering, small gas losses, and clerical errors, which in a well-maintained storage field operation should already be minimal; and (3) AIU's failure to show that the gas losses associated with performance variations have physically left the storage fields.

b. AIU's Position

AIU provides four reasons why the Commission should reject Staff‗s proposal. AIU states that the language of Account 823 makes clear that ―performance variations" are properly accounted for in Account 823. AIU asserts that Staff concedes that not all performance variations are in fact migrations to non-recoverable base gas, so transferring all ―performance variations" from Account 823 to Account 352.3 is improper. AIU contends that the Commission has determined that gas losses are properly accounted for in Account 823. Finally, AIU claims transferring gas loss amount from Account 823 to Account 352.3 would require adjustments to rate base for the prior years.

AIU asserts that the language of Account 823 is broad, encompassing gas that is either lost or is otherwise unaccounted for due to cumulative inaccuracies of gas measurements or other causes. In AIU's view, an inventory adjustment for gas that is unaccounted for any cause is properly included in Account 823. AIU asserts that there is no requirement in the language of Account 823 requiring that lost gas recorded in that account relate to gas lost in a specific incident, or even that lost gas recorded in Account 823 be a ―physical" loss of gas.

AIU claims that the types of ―performance variations" Mr. Anderson refers to, such as errors introduced over long periods, losses that occur that are unknown or of small magnitude, and accumulated clerical errors, metering inaccuracies, and other operational/maintenance losses, are the exact ―cumulative inaccuracies of gas measurements" that should be recorded in Account 823. AIU believes that even what Mr. Anderson would call migration to non-recoverable base gas can be recorded in Account 823, as it represents gas ―unaccounted for in underground storage operations due to . . . other causes."

AIU asserts that Account 352.3 does not refer to the calculation or recording of gas losses. Account 352.3, AIU argues, refers to gas in the reservoir, so it is not an appropriate account in which to record lost gas. According to AIU, the gas described by Mr. Anderson as a performance variation is not in the field reservoir and so is lost. AIU claims it is incorrect to account for virtually all of the ―lost" gas in Account 352.3, and Mr. Anderson‗s testimony does not support the wholesale transition of amounts in Account 823 to Account 352.3. In AIU's view, Mr. Anderson‗s performance variations are lost gas, and as such should be recorded in Account 823. AIU says that, although there may be an appropriate distinction between physical losses that can be estimated with engineering calculations and losses that can not be estimated, there is no basis for a different accounting treatment of measurable physical losses and other gas losses from a storage field.

AIU states that reservoirs can not hold an infinite volume of gas, and in its present form, AIU believes Staff's recommendation to continually transfer performance variations to non-recoverable base gas does not take into account the ability of the reservoir to hold these volumes of gas. AIU asserts that continually adding performance variation adjustments to the non-recoverable base would eventually cause the amount of gas recorded in Account 352.3 to exceed the capacity of the reservoir to hold gas, at least from an accounting standpoint. AIU also claims it would cause rate base related to the gas storage field to increase substantially over time.

AIU claims that some performance variations are physical losses of gas, and that not all performance variations represent migration to non-recoverable base gas. AIU further asserts that such physical losses could be recorded in Account 823. The fact that performance variations include physical losses and do not entirely consist of migration to base gas completely, AIU argues, undercuts the rationale for Staff‘s proposed shift to Account 352.3.

According to AIU, Staff‘s position is that some, but not all, of the performance field variations described by Mr. Anderson represent gas that has migrated to base gas and should be recorded as non-recoverable base gas. AIU says Staff admits that so-called performance variations can include physical losses of gas as well as gas migrating to non-recoverable base gas. AIU argues that if performance variations can include physical losses, then under Staff‘s logic, some performance variations are properly included in Account 823. AIU complains that Staff has not changed its recommendations regarding shifting gas losses to Account 352.3 and continues to recommend that all of the so-called performance variations be placed in Account 352.3. AIU avers that if it is possible that performance variation could include actual physical losses, then those performance variations should remain in Account 823.

AIU also complains that Staff does not quantify what part of performance variations are physical losses and what part is migration to non-recoverable base gas. Moreover, Staff agrees that such quantification is not feasible. In AIU's view, Staff established no basis for shifting the costs to Account 352.3, when accounting for such losses in Account 823 is reasonable and appropriate. AIU also claims that Staff has not explained why, if performance variations include physical losses, such losses would not be gas lost through —other causes.” Theoretically, AIU states, some of the performance variation gas could migrate to base gas; however, AIU claims there is no known technique by which to separate performance variations into lost gas or non-recoverable base gas. AIU asserts that these migration losses would be very small in scale. AIU believes it is appropriate to include this gas loss as part of the annual gas loss adjustment in Account 823.

This proceeding, AIU asserts, is the first time AIU has been confronted with the concept of performance variations. AIU also says that the term ―underground storage field performance variation” is not a term commonly used in the gas industry. AIU asserts that because the concept of performance variations is a new one, AIU has not had the opportunity to fully analyze it. AIU claims it has not been able to identify a method whereby one could quantify the difference between various physical losses and losses of working inventory to non-recoverable base gas as a result of normal operations. AIU claims it is not aware of any methodology to quantify what components of performance variations are lost gas and what might migrate to non-recoverable base.

In Docket No. 04-0779, AIU says the Commission found that a withdrawal factor, representing gas losses, used by Nicor was appropriately included in Account 823 as an operating expense. (AIU Initial Brief at 223-224, citing Docket No. 04-0779, Order at 39-40) AIU says in that case, a Staff witness testified that expenses related to the operation of a storage field, including adjustments for inventory losses due to cumulative inaccuracies of gas measurements or other causes, should be recorded in Account 823. AIU asserts that even though a portion of the gas was for the replenishment of gas volumes that have become non-effective in contributing to the performance of the storage reservoir, the entire amount was charged to Account 823. The Commission ruling in the docket, AIU states, ultimately approved this treatment of the lost gas. According to AIU, the Commission has approved recording gas storage losses of the type Mr. Anderson calls performance variations in Account 823.

AIU complains that Staff's recommendation does not treat gas consistently from year to year. AIU says Staff suggests capitalizing certain gas losses for 2006, thus reducing AIU's test year expense and increasing rate base. If Staff's recommendation is followed, then AIU asserts like gas losses should be evaluated and capitalized as well, and become a part of rate base. AIU claims that taking what Mr. Anderson describes as performance variations and reclassifying them as non-recoverable base gas would, at present, result in increases to rate base.

Ms. Everson disagrees that adjustments to past year rate bases are needed. With respect to AmerenCILCO, Ms. Everson states that AmerenCILCO was recovering these costs through its PGA. At the time of the last rate case, AIU says these costs were not included in the base rates and therefore have not been collected. AIU states it is true that from the 2004 PGA reconciliation and before, the gas losses were collected ultimately through the PGA mechanism and the 2005-2007 reconciliations are still pending a final Commission order. AIU claims that as long as the gas loss costs continue to be collected through the PGA, AIU would agree that these costs should not be included in Account 352.3 for prior years. AIU contends that under Staff's proposal, if these costs are not included in the PGA, then the total sum of those losses from prior years 2005-2007 should be included in Account 352.3.

AIU states that AmerenCIPS (Docket No. 02-0798) and AmerenIP (Docket No. 04-0476) did submit certain gas loss expenses, related to estimated physical losses for discrete events, in Account 823 in their last rate cases. AIU asserts, however, that they did not submit any expenses related to performance variations as that term is currently defined by Mr. Anderson. Therefore, AIU claims there would not be any recovery from the ratepayers for those gas loss expenses and they would not be included in base rates. After the last rate cases, AIU says AmerenIP and AmerenCIPS began recording gas losses resulting from accumulated clerical and accounting errors, metering inaccuracies, and other operational or maintenance losses (in addition to estimated physical losses related to discrete events) in Account 823. Thus, AIU states that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording. According to AIU, Staff is now proposing that such gas losses should be prospectively recorded to rate base. AIU contends that under Staff's proposal, such costs should have been recorded to rate base in past years. If the Commission adopts Staff's proposal, AIU insists such past year gas loss costs should be transferred to rate base in this proceeding. Otherwise, AIU believes there would be a situation where the higher gas loss costs recorded to Account 823 since the last rate cases for AmerenIP and AmerenCIPS would not be recovered, since they are not presently in base rates and would not be placed in rate base under Staff's proposal in this case. AIU claims that the volumes shown in Mr. Underwood's rebuttal testimony for AmerenIP and AmerenCIPS represent volumes that should be reclassified as non-recoverable base gas if the Commission adopts Staff's proposal, resulting in the associated increases to rate base.

According to AIU, Staff argues that further evidence supporting Staff's position that migration is a major cause of performance variations is AmerenCIPS' adjustment to significantly increase the non-recoverable base gas at its Sciota storage field. AIU claims this position was not set forth in the testimony of any witness. AIU argues that, nevertheless, Staff's argument is without merit because AmerenCIPS' adjustment to increase the non-recoverable base gas at its Sciota storage field represents a determination that gas in the reservoir should be reclassified. AIU claims a detailed reservoir study, as well as a seismic study and a petrophysical review, was completed to specifically identify the amounts of gas in the Sciota field that should be adjusted to non-recoverable base. AIU contends that the results of this study determined how the volumes should be adjusted in that particular instance. AIU says this report, which was based on years of operating experience, new seismic studies of reservoir information, and reservoir simulations, enabled more accurate estimates of the volumes. In the case of performance variations, however, AIU says that it and Staff agree that there is no way to calculate what part of performance variations, if any, is migration to non-recoverable base. AIU insists that the fact that base gas in the reservoir at Sciota was reclassified to non-recoverable base says nothing about the proper accounting of lost gas. AIU also believes this reclassification says nothing about the proper accounting of lost gas, which Staff calls performance variations.

AIU also takes issue with Staff's assertion that transferring performance variations from Account 823 to Account 352.3 would be seamless from a cost recovery standpoint. AIU says Staff rejects AIU's position that the amounts in AmerenIP's and AmerenCIPS' current base rates do not reflect the full amount of expense that these two utilities now charge to Account 823. Staff argues that actual amount of an expense may be greater or less than the amount for which recovery is allowed in a prior rate case. AIU states that, while this is correct for an operating expense, Staff is proposing to switch performance variation amounts to a rate base account. AIU says that if performance variations are recorded in a rate base account, they represent an investment by the utility. AIU claims that, while its current filing recovers the full annual amount of gas loss expense recorded to Account 823, a shift of that amount to rate base would leave prior years' investment stranded. AIU maintains that the base rates for AmerenIP and AmerenCIPS reflect smaller amounts of gas loss expense than AmerenIP and AmerenCIPS are currently recording.

According to AIU, Staff's reference to Dockets Nos. 02-0717 and 03-0396 as supporting the position that the gas loss accounting issue is nothing new are unavailing. AIU says those cases dealt with the question of whether gas losses should be recovered through the PGA or base rates. AIU claims the cases did not address which Account, 823 or 352.3, was the correct account to record such gas losses. AIU adds that they did not address the treatment of performance variations.

c. Commission Conclusion

Currently, AIU apparently records all gas losses in Account 823, which is an operating expense account. Staff proposes that AIU record all gas losses characterized by Mr. Anderson as performance variations in Account 352.3, which is a rate base account. While maintaining its position, AIU claims that if Staff's proposal were adopted, additional changes to rate base accounts for previous years would be required for AmerenCIPS and AmerenIP. Staff disagrees that any additional adjustments would be required.

Staff argues that the migration of gas to nonrecoverable natural gas is likely the primary cause of gas losses, although Staff does not know for sure what portion of gas losses have migrated. AIU does not go quite so far, although AIU does not seem to actually dispute the proposition that a portion of gas losses could easily be a result of gas migration. Instead, AIU relies on the broad language describing Account 823 and appears to suggest that any gas loss could be recorded in Account 823.

The record supports the accounting perspective that a portion of the gas losses should, in all likelihood, be recorded as a rate base item with the remainder recorded as an operating item. Because each of the extreme positions taken here seems likely to be improper, the Commission is faced with a rather difficult decision. The Commission finds the testimony of Mr. Anderson regarding the migration of gas to be the most convincing and, as a result, adopts Staff's proposed adjustments on this issue. The Commission finds that AIU should record gas losses for the test year in Account 352.3 as presented on Staff Schedules 14.04 G. In future rate cases, AIU is free to attempt to quantify the portion of gas losses resulting from the migration of gas and seek different accounting treatment of other gas losses.

Contrary to AIU's assertion, the Commission does not believe any additional adjustments for gas losses prior to the test year are necessary for AmerenCILCO, AmerenCIPS, or AmerenIP. To the extent amounts representing gas losses have been recorded in Account 823 and reflected in operating expenses in prior rate cases, no adjustments are necessary as the change ordered herein will be reflective of the test year and will be effective prospectively. To the extent gas losses have been recorded in

Account 823 and are reflected in AmerenCILCO's PGA reconciliations, as long as the gas losses receive appropriate treatment for the appropriate reconciliations, the utilities will be made whole. Additionally, the Commission directs AIU and Staff to make all reasonable efforts to ensure that gas losses are treated in a manner consistent with this decision for the outstanding 2005-2007 AmerenCILCO PGA reconciliations.

7. Working Capital Allowance for Gas in Storage

a. AIU's Position

AIU proposes that its working capital allowances for gas in storage be $53,023,000 for AmerenCILCO, $37,731,000 for AmerenCIPS, and $99,903,000 for AmerenIP. AIU understands that Staff proposes certain volume adjustments to the working capital allowance for gas in storage. In response, AIU indicates a willingness to accept Staff's proposal, and also proposes what AIU sees as the necessary counterpart adjustments. AIU asserts that if the Commission chooses to accept Staff's pro forma volume adjustments reflecting adjustments for normal weather and changes in leased storage contracts; the Commission should adopt AIU's proposed pro forma price adjustments.

AIU agrees in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. AIU submits that Staff witness Lounsberry's analysis on this issue contains only half of the necessary adjustments. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. Staff's adjustment, according to AIU, assumes that the per unit costs of the test year (2006) are valid in the year associated with Staff's pro forma inventory levels (2008); AIU argues this is not correct.

AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the New York Mercantile Exchange ("NYMEX") natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU avers that on April 8, 2008, that price was $10.00 per millions of British thermal units ("MMBtu") for the period. Mr. Lounsberry opposes AIU's pro forma adjustment to gas storage working capital to account for the significantly higher prices of natural gas in the calculation of inventory costs for three reasons: he believes that the 2008 prices are now known and measurable or determinable; he claims that AIU price hedge portions of its storage injection gas; and he believes that the 2006 per unit costs are in line with 2007 costs.

AIU asserts that with respect to Mr. Lounsberry's argument that 2008 prices are not known, measurable, or determinable, his own calculations are also predicated on projected (rather than known and measured) forecast volume data. AIU argues that Mr. Lounsberry is implying that the volume adjustments are also not known and measurable. AIU avers that Mr. Lounsberry's premise for his proposed volume adjustments are two-fold; changes in AIU's leased storage levels and attempting to account for the warmer than normal weather realized during the 2006 test year. AIU argues that Mr. Lounsberry requested —expected” ending inventories —assuming” normal weather and utilized these as forecasted volumes instead of historical volumes that occurred during the test year. AIU submits that its request to reflect the forecasted cost of gas injected into its storage fields is no different than Mr. Lounsberry‘s use of the forecasted ending storage volumes.

AIU contends that part of Mr. Lounsberry‘s volume adjustment argument stems from his premise that 2006 was a warmer year than normal and that, for the test year 2006, AIU retained more gas in inventory than it would have in a year of normal weather. AIU submits that there are issues in addition to weather that are also important to the cycling of storage fields. AIU avers that it examined the ending inventories in AIU's storage fields, leased and owned on December 31, 2006, and the forecast inventories on December 31, 2008, and made known contractual changes. AIU argues that after this examination, it can not agree with Mr. Lounsberry‘s volumetric adjustments associated with the difference between 2006 and 2008 weather, as Mr. Lounsberry has outlined a difference in degree days of approximately 10% between 2006 actual and 2008 normal. AIU submits that while such a difference may have a large impact on annual throughput and earnings from the utility‘s perspective, it would not necessarily make a large difference in how the storage fields are operated. AIU further submits that the specific characteristics of each storage reservoir are another factor affecting the withdrawal plan.

AIU concurs with Mr. Lounsberry‘s concern that its price hedge portion of the injection gas supply is not reflected in the proposed price adjustments. AIU points out that its risk management policy outlines a hedging strategy for up to 50% of its summer injection requirements. Therefore, AIU asserts it recalculated the projected storage Weighted Average Cost of Gas ("WACOG") for the pro forma test year. AIU submits that utilizing the utilities' hedged positions for the entire period of 2008 currently in place, actual storage inventories and prices through April 2008, and the NYMEX forward strip as of April 24, 2008, this calculation produces WACOGs of $8.79 to $9.00 per MMBtu. AIU avers that this result is reasonably comparable to the $10.00/MMBtu NYMEX strip used previously.

As a result of this analysis, AIU argues it has reduced its price adjustment on a per MMBtu basis, and the impacts that these revised WACOGs have on the storage working gas inventory balance result in AIU's current proposal for gas storage working capital allowance. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side. AIU avers that it is clear that the cost of AIU gas inventories on December 31, 2008, will be equal to or greater than at the end of 2006. AIU notes that in 2006, gas commodity prices at the Henry Hub averaged $6.74 per MMBtu; while through April 21, 2008, actual Henry Hub gas prices averaged $9.27 per MMBtu, a 37.5% increase over 2006. AIU avers that the NYMEX forward curve for the remainder of 2008 indicates an average market price of $11.11 per MMBtu, reflecting a 65% increase over the 2006 cost levels.

AIU recommends that the Commission adopt the level of working gas inventory in the working capital adjustment that AIU filed in its direct cases. Should the Commission adopt Staff's pro forma volume adjustments, AIU submits that the Commission should further adopt AIU's pro forma price adjustments.

b. Staff's Position

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff points out that AIU witness Wichmann states that AIU does not dispute the rationale for Staff witness Everson's adjustment regarding the accounts payable percentage, but does not agree with the value Mr. Lounsberry assigned to gas in storage.

Staff submits that its recommended alterations to amounts that AIU has requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields. Staff recommends changes to all of AIU's requested volumes due to the determination that AmerenCILCO and AmerenCIPS had known and measurable changes to their test year volumes, AmerenIP's test year volumes had changed and the 2006 test year was not a representative year. Staff points out that in order to calculate the adjustment, Mr. Lounsberry employed the same methodology that Staff used and the Commission accepted in the recent Peoples/North Shore rate cases on this issue, Docket Nos. 07-0241/07-0242 (Cons.).

For known changes, Mr. Lounsberry noted that AmerenCILCO's storage volumes were being increased due to increases in its Panhandle Eastern Pipe Line Company ("Panhandle") storage volumes effective April 1, 2006, as well as April 1, 2008. AmerenCIPS' storage volumes also changed by having its Panhandle contractual volumes decrease effective April 1, 2008, as well as decreased storage volumes from Texas Eastern Transmission Corporation as of July 1, 2006. Mr. Lounsberry further noted that AmerenIP had increased storage volumes from the Mississippi River Corporation as of May 16, 2006, increased the storage volumes received from Panhandle and ANR Pipeline Company as of April 1, 2006, and reduced storage volumes from Trunkline Gas Company as of April 1, 2006.

According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields, and that warmer weather, in general, creates a situation where more gas remains in the field than the utility had planned. Staff submits that since a utility's working capital allowance is based upon the volumes of gas remaining in storage, this means that a utility's working capital allowance for gas in storage in a warmer than normal year is higher than if it was based upon a year with normal temperature conditions.

Given Staff's concern's, Mr. Lounsberry calculated AIU's storage volumes using a normal 2008 year. Staff asserts this methodology ensures that AIU's storage volumes are normalized, rather than relying on historical storage volumes that are often impacted by temperature conditions that vary from the norm, and also accounts for the known and measurable changes that the AIU made to its storage volumes. Staff submits that Mr. Lounsberry's calculations were based upon AIU's projection of the storage volumes it would maintain in 2008 under the assumption a normal year occurred.

Staff recommends that the Commission adopt its suggested changes and set working capital allowances of $45,089,000 for AmerenCILCO, $32,259,000 for AmerenCIPS, and $82,396,000 for AmerenIP.

c. CUB's Position

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions.

AIU, according to CUB, did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations that AmerenCILCO decrease its requested amount by approximately $4,359,000, that AmerenCIPS reduce its requested amount by approximately $13,669,000 and that AmerenIP reduce its requested amount by approximately $5,105,000.

d. Commission Conclusion

Staff proposes an adjustment to reduce AIU's gas in storage inventory by the amount of accounts payable for the costs associated with the purchase of general materials and supplies and gas in storage inventory. Staff submits that its recommended alterations to amounts that AIU requested for its working capital allowance for gas in storage are due to known and measurable changes in the gas volumes that AIU would maintain at its storage fields.

AIU agreed in part that Staff's adjustments are acceptable, since there are new leased storage contracts in place and pro forma adjustments can be made for known and measurable changes. According to AIU, if pro forma adjustments are made to the volume side of the equation, then the price side of the equation requires adjustment as well. AIU submits that inventory costs in 2008 will not be equal to past years' costs. To reflect 2008 prices, AIU proposes what it calls a reliable proxy: the NYMEX natural gas futures price strip for the period April through October 2008, which it argues is the traditional injection season for all of the on-system and leased storage inventory. AIU avers that on April 8, 2008, that price was $10.00 per MMBtu for the period, which was subsequently adjusted in an effort to reflect the fact that AIU hedges portions of the injection gas supply. AIU submits that it would be improper to allow a pro forma adjustment to be addressed on the volume side while ignoring the commodity price side.

CUB argues that a vast majority of storage gas is injected during non-winter months, and therefore there is a lag between when a utility injects the gas into a storage field or leased storage service (and pays its supplier for that gas) and when the utility withdraws that gas and receives its payment for the same gas. CUB proposes that AIU revise its requested working capital amounts to account for known changes of its gas in storage and to account for the normal temperature conditions. According to CUB, AIU did not properly account for the inherent lag between injection and withdrawal in gas storage, and therefore, the Commission should rely upon Mr. Lounsberry's recommendations.

The Commission finds Staff's proposal to make pro forma adjustments to the working capital allowance to reflect revisions in storage volumes to be reasonable and it is hereby approved. The Commission believes that these adjustments will better reflect AIU's cost structure that will be in place when rates established in this proceeding take place. While Staff objects to AIU's proposal to make adjustments to the price associated with gas in storage, the Commission believes it appropriate. AIU made an adjustment to the proposed price to reflect the fact that it hedges a portion of the gas injected into storage in direct response to Staff's concern. Contrary to Staff's suggestion, the use of NYMEX natural futures contracts is not unheard of in establishing rates. The Commission concludes that in this instance, the price proposal of AIU is reasonable when used in conjunction with Staff's proposed quantities of gas.

As for CUB's proposal, the Commission has established the appropriate CWC allowance elsewhere in this Order and believes there is no point in addressing the issue here.

8. Hillsboro Base Gas Inventory Valuation (Prior Adjustment)

a. AIU's Position

AmerenIP seeks to include in rate base $10,367,838 associated with base gas inventory at the Hillsboro Storage Field. In doing so, AIU is essentially asking the Commission to revisit its decision in Docket No. 04-0476 disallowing this amount. Even though an appellate court upheld the Commission's disallowance, AIU argues that circumstances have changed since Docket No. 04-0476. AIU wants the Commission to consider the fact that the Hillsboro Storage Field has now been restored to its full ―used and useful" levels for peak deliverability to system sales customers, which was not the case in the previous proceedings. AIU argues that it is not just the Hillsboro field that is used and useful, the $10,367,838 cushion gas amount is also used and useful. AIU claims that AmerenIP is not currently being allowed to earn a return on assets that are used and useful, prudently incurred, and providing full benefits to its customers.

Gas storage operations, AIU argues, benefit its gas customers. According to AIU, system storage provides flexibility and reliability for gas supply to customers that can not be found elsewhere for the same value. AIU says this flexibility on the natural gas system allows for the efficient balancing of supplies and usage. AIU adds that the storage fields provide reliability by being a source of gas supply close to the customers, therefore reducing risk related to facility failure or disruption to the supply of gas.

AIU contends that on-system storage also generates financial benefits for gas customers, by lowering the price of gas. When combined, AIU indicates that the peak day deliverability of AmerenCILCO, AmerenCIPS, and AmerenIP, is 1,182,264 MMBtu, with a storage delivery of 578,759 MMBtu (48% of the peak day send out of the combined utilities). AIU asserts that replacing the storage deliverability of AmerenIP with interstate pipeline deliverability would increase the PGA costs by almost $100 million a year, not including any seasonal differential associated with the commodity purchases. In AIU's view, gas storage provides ratepayer benefits, and AmerenIP should be allowed to recover its reasonable and prudent expenses related to gas storage field operation, including the Hillsboro Storage Field base gas inventory.

In Docket No. 04-0476, the Commission addressed a situation in which AmerenIP had withdrawn cushion gas from the Hillsboro field due to a metering error. As a result of the over-withdrawals from the field, AmerenIP had to replace the withdrawn cushion gas with gas purchased at higher prices than the historical cost of the cushion gas reflected in rate base in Illinois Power's 1993 rate case. The Commission agreed with the Staff, and concluded that the excess of the replacement cost over the historical cost of the cushion gas could not be recovered until the gas is withdrawn from the field at the end of the field's useful life, and that AmerenIP could not earn a return on the excess cost in the interim.

AIU claims that the effect of the decision imposes a penalty on AmerenIP out of proportion to the effect on customers. AIU claims the error provided lower cost gas to customers than they otherwise would have received. AIU states that AmerenIP must bear the financing costs of a portion of its cushion gas for the remaining useful life of the field, which could be 30 years or more. From AIU's perspective, customers receive the double benefit of both the consumed lower priced gas withdrawn from the field and the historical cost of the cushion gas for the remaining life of the field. AIU claims it will essentially lose its investment in the additional costs of the replacement gas. By the time AmerenIP obtains any recovery of the investment, AIU complains that it will have incurred financing costs far in excess of its investment.

AIU proposes at least two ways to address this situation. One is to reflect the full value of the cushion gas in rate base in this proceeding. AIU maintains that customers have benefited both from the lower cost gas through the PGA and avoided financing costs on the additional investment for three years. AIU believes the lost financing cost over those three years is an adequate revenue impact for AmerenIP, especially since the field has been returned to its full used and useful status. Alternatively, AIU suggests that the Commission could allow it to recover the excess cost, which AIU claims is roughly the cost customers should have paid through the PGA, in this case. AIU says that under this approach, customers avoid several years of financing costs, the inventory is priced going forward as though the metering error were never made, and at the end of the useful life of the field customers will receive even lower priced gas.

AIU also asserts that the management concerns at Hillsboro raised in Docket No. 04-0476 have been addressed. AIU states that Staff witness Lounsberry acknowledges that most of the problems he identifies related to the Hillsboro Storage Field existed prior to 2004, that he has not seen a reoccurrence of those problems, and that he is aware of improvements made in ―management oversight" of gas storage at AmerenIP since December 2000. Since 2004, AIU explains that several significant organizational changes and improvements have been made to improve gas operations, which emphasized the importance of the gas storage operations at AmerenIP's gas facilities, and provided continued value to its customers. AIU asserts that improvements have also been made to the operations of the gas storage fields, including concentration on the metering area. AIU notes that new ultrasonic metering installations were performed at Ashmore in 2005, Tilden and Hillsboro in 2006, and Shanghai in 2007, and there are plans to install new metering facilities at Hookdale and Freeburg in 2008. These improvements, AIU asserts, make higher levels of operation performance possible through the availability of better equipment.

According to AIU, several recently-completed capital projects have also contributed to improvements in AmerenIP's operations. AIU states that $3.1 million in capital expenditures were made in 2006, and over $7 million of capital expenditures were made in 2007, all related to improving performance at gas storage fields. AIU relates that some of the larger projects include the previously mentioned facility metering projects, water disposal system, hydrogen sulfide ("H_2S") removal facilities, replacing motor control centers, adding gas chromatographs, and replacing a glycol regenerator. AIU claims that these improvements and changes have had a measurable impact on gas storage field performance since 2004. AIU notes that for all AmerenIP gas storage fields, including Hillsboro, there has been no increase or decrease of peak day ratings. Overall, AIU claims that the fields have been performing well and have provided value to the ratepayers, without the storage field customers having to pay more in PGA costs.

In its Reply Brief, AIU states that in Docket No. 04-0476, Staff viewed the disallowance in part as a penalty for poor management at Hillsboro. AIU observes that Staff acknowledges there have been numerous improvements and investments at Hillsboro since 2004. As a result, AIU argues that the past problems do not persist and do not represent present concerns. According to AIU, the concerns about Hillsboro that Staff raised in Docket No. 04-0476 in recommending the disallowance of the $10,367,838 amount have been addressed. In AIU's view, because AIU addressed these concerns, the rationale for penalizing AmerenIP for its poor management at

Hillsboro has been eliminated, and the $10,367,838 disallowance should be reconsidered.

b. Staff's Position

Staff objects to AIU‘s request to revisit the issue of revaluing a portion of the Hillsboro Storage Field‘s base gas inventory. Staff says AIU requested the Commission‘s permission to increase the value of its recoverable base gas inventory at Hillsboro by $10,367,838 in Docket No. 04-0476, AmerenIP‘s last gas rate case. AmerenIP‘s basis for that previous request, Staff states, was that it experienced a significant gas measurement error at its Hillsboro field during the period November 1993 through October 1999. AmerenIP estimated that the impact due to the measurement errors caused its measurement records to overstate its actual gas inventory by 5.8 billion cubic feet (―Bcf”). AmerenIP also claimed that, as a result of the measurement error, it withdrew gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes, and withdrew gas from its recoverable base gas inventory. According to AmerenIP, the impact of this activity was that it withdrew recoverable base gas that was lower-priced than the gas it had placed in the field during the injection season, resulting in AmerenIP‘s request to increase the value of its recoverable base gas inventory at Hillsboro by $10,367,838.

Regarding AIU's primary proposal, to include the cost of gas in rate base, Staff says this methodology was fully discussed and argued before the Commission in AmerenIP‘s last rate case. At that time, the Commission agreed with Staff and denied AmerenIP‘s request to revalue the base gas inventory at Hillsboro. Staff notes that AmerenIP appealed the Commission‘s decision to deny its request to revalue the base gas inventory at Hillsboro, and on October 2, 2006, the appellate court affirmed the Commission‘s decision. In Staff's view, AIU did not provided any new arguments or information in this proceeding for the Commission to consider that would support a change in the Commission‘s prior decision.

With regard to AIU's secondary proposal to create a regulatory asset and amortize it over two years, Staff argues this would provide no benefit to ratepayers in that it would essentially allow AmerenIP to expense an item that would normally be a rate base item. Staff claims AIU‘s proposal would only provide a benefit to AmerenIP without a corresponding benefit to its ratepayers. AIU claims that it was not attempting to reverse the Commission‘s prior decision in AmerenIP‘s last rate case or to prove the Commission wrong. Instead, AIU indicates that it is asking Staff to give new consideration and weight to the fact that the Hillsboro field has been restored to its full ―used and useful” levels for peak deliverability to system sales customers and that the full amount of the cushion gas is being used to provide that full ―used and useful” level of peak deliverability. According to Staff, AIU is advocating a reversal of the Commission‘s prior Order. The Commission‘s Order on this issue in Docket No. 04-0476 not only provided a conclusion on this issue, but also clearly directed the manner in which AmerenIP would recover its costs in the future. Staff says the cost will ultimately be recovered through the PGA clause when the gas is withdrawn and delivered to PGA customers.

Staff claims that AIU's only basis for reversing the Commission's prior decision is that the Hillsboro field is now fully —used and useful" and it provides peak deliverability. According to Staff, the Commission's Order in Docket No. 04-0476 clearly provides a separate discussion and conclusion regarding the issue of the inventory revaluation, versus the used and useful discussion and conclusion. Staff also contends that AIU is in error to claim that the Hillsboro field was not at peak deliverability during AmerenIP's last rate case. Staff says the Commission's Order clearly indicates that IP had restored the peak day deliverability rating of the Hillsboro field to its design level prior to the 2003-2004 winter season, which is prior to AmerenIP's rate case filing in Docket No. 04-0476. In Staff's view, AIU presented no basis for a reversal of the Commission's prior decision in Docket No. 04-0476. Staff recommends that the Commission deny AIU's request to revalue the Hillsboro field's base gas inventory by $10,367,838, or, in the alternative, to account for this value in another manner.

c. Commission Conclusion

Despite AIU's protests, it appears to the Commission that the circumstances here are identical to those present in Docket No. 04-0476. In that case, the Commission rejected AmerenIP's proposal to include in rate base the additional base gas at Hillsboro, which is the request AIU repeats here. The Commission previously decided this question, this decision was affirmed by the appellate court, and the Commission can discern no change in facts or circumstances that warrant revisiting or reconsidering the question here. AIU's proposal is rejected.

9. Hillsboro Base Gas Inventory Valuation (New Adjustment)

a. AIU's Position

AmerenIP proposes to add $2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims that the addition is necessary to account for base gas lost through a valve leak. According to AIU, the added volume represents gas that is now used and useful in providing service to customers, and the cost of the added gas has been prudently incurred.

AIU states that tests on newly-installed ultrasonic gas meters at Hillsboro in January 2007 revealed that base gas volumes at Hillsboro must be adjusted. After the installation was completed, AIU says comparisons were made between the flow through the existing metering and the new metering. After analyzing the data, AmerenIP indicates it determined that 1,109,964 Mcf of additional gas was actually withdrawn but not reflected as withdrawals from the field from 2001-2007. AmerenIP says it replaced this 1,109,986 Mcf of gas by the end of the 2007 injection season, resulting in an adjustment of an additional $2,841,000 to the Hillsboro base gas account.

AmerenIP determined that there was a valve leak in the old metering equipment, which allowed gas to pass undetected and unmeasured through the secondary meeting run, over the period 2000 to 2007. AmerenIP says this resulted in a portion of base gas being withdrawn during the years 2001 to 2004, which was delivered to AmerenIP's sales customers. This base gas was replaced during the next injection season after the gas was withdrawn. AIU asserts that the replacement was required in order to meet the supply requirements of AmerenIP's gas customers because the proper operation of the storage field requires that the base gas be present to provide pressure support for the field. To assure the field can cycle 7.6 Bcf and peak at 125,000 Mcf/day, AIU explains that the field must have the established level of base gas and working gas. According to AIU, this is an investment that was required to meet the needs and requirements of AmerenIP's customers. AIU believes that the gas loss at Hillsboro was justifiably re-injected into the reservoir.

AIU argues that it is in the best interest of the ratepayers and AmerenIP to make regular adjustment for gas losses. Deferring an annual adjustment until ironclad support of a shortfall in inventory is in hand, AIU avers, could potentially cause a storage field to fall short of its delivery target, due to the cumulative effect of not making annual adjustments. AIU claims a shortfall in storage field gas could cause it to buy spot-market gas or overrun a pipeline contract to make up the shortfall. AIU says this would be an additional expense to ratepayers. AIU asserts that if it does not make timely additions to inventory it is possible that at some time in the future it will need to add a relatively large amount of gas to make up for the cumulative shortfall. AIU contends that this gas, in all likelihood, would be more costly than an annual addition of smaller amounts of gas.

AIU reports that Staff witness Lounsberry recommends disallowance of the $2,841,000 addition to the Hillsboro base gas account. Mr. Lounsberry originally set forth four reasons for disallowing this request to increase its recoverable base gas costs. Mr. Lounsberry argued that: (1) he does not consider AmerenIP's logic in determining the timing of the metering error at Hillsboro during the years 2001–2004 as valid; (2) AmerenIP has inadequate support for the assigned value; (3) he questions the validity of certain assumptions that AmerenIP made as part of the calculation; and (4) he states that, given the purported history of problems at Hillsboro, he would have expected AmerenIP to have conducted a review of the integrity of the valve at a much sooner date.

Mr. Lounsberry argues that it was not reasonable to assume that the valve leak in question began in 2000. AIU responds that while the start date of the valve leak is uncertain, AmerenIP selected 2000 as an estimate for the start date because that was the half-way point between when the valve was rebuilt (1993) and when the leak was discovered. AIU believes use of the halfway point is also reasonable because the 5.8 Bcf correction that the 2004 Hillsboro Study recommended would have accounted for all metering errors, including withdraw metering errors, up to 2000 only. AIU states that after 2000, as a result of AmerenIP's 1999 Meter Study (Peterson), the method of operating the storage field changed so that injection meter error was eliminated. AIU adds that only data from the 1994 to 1999 time period was modified in the reservoir simulator's data deck to determine that the inventory shortfall was 5.8 Bcf. Injection data from 2000 to 2003 was accepted at face value, AIU says. Hence, AIU claims the impact of the valve leak metering error had already been corrected for the period up to 2000, and need only be accounted for thereafter.

Mr. Lounsberry's second concern is that AIU has not sufficiently supported the $2,481,000 assigned value of the base gas cost. Mr. Lounsberry cites two bases for his position: AmerenIP's inconsistent operation of Hillsboro makes it unreasonable to rely on reservoir data, and AIU's current proposal conflicts with data reviewed in a prior rate case. AIU asserts that no party challenged the two forms of input data in the data plot that AmerenIP uses to support the measurement error correction. AIU says the first data input is gas volume data, which are from the new ultrasonic metering, not the old plant metering, and therefore are considered to be accurate. AIU indicates that the second data input is pressure data, which are measurements of the wellhead pressure from the Truitt #1 pressure observation well. According to AIU, at no time has Mr. Lounsberry questioned the validity of this wellhead pressure measurement. AIU states that while Mr. Lounsberry asserts that AmerenIP may have employed other ―superior" methodologies in past rate cases, AmerenIP used valid reservoir engineering techniques to determine gas loss. AIU argues that it is not required to use any one particular type of study to demonstrate prudence. (AIU Initial Brief at 108-109, citing Illinois Power Co. v. Illinois Commerce Comm'n., 339 Ill. App. 3d 425, 439 (5th Dist. 2003) (―Section 9-220(a) of the Act does not set forth any specific type of analysis that a utility must perform to show that its costs are prudent.")

AIU agrees that the reservoir model would be an appropriate method to determine gas losses; however, AIU says the reservoir simulator was not used to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections. Further, AIU claims techniques such as hysteresis curves and reservoir simulation techniques are not viable at Hillsboro at this point in time due to the present state of the data (in the case of the simulator), and the variation in gas volumes cycled (in the case of hysteresis curve analysis). AIU asserts that it used the best data available in its calculations. AIU maintains that the data available are sufficient to allow the base gas adjustment to be calculated based on sound engineering judgment. AIU states that as gas is injected and withdrawn from a reservoir, wellhead pressure will vary. AIU says this change in pressure can be, and is, utilized by AmerenIP to monitor reservoir performance via multiple techniques such as reservoir simulation, hysteresis curve analysis, the Tek Methodology procedure, and many other techniques. AmerenIP says it utilizes this information at all of its fields in one form or another as part of its ongoing inventory verification process. AIU concludes there is no basis to believe that the result of these two sources of data is in any way unreliable.

AIU asserts that Mr. Lounsberry ignores the results of the 2007 Hillsboro inventory adjustment. In 2006, when the 2006 Gas Loss Adjustment Report was written, AIU says it believed that the hysteresis curve analysis, modeling, and neutron log evaluation for Hillsboro were, in fact, affected by the injection of additional gas into the field. But AIU claims that it also recognizes that gas losses are occurring on an ongoing basis in gas storage fields. In light of this fact, AmerenIP decided to inject 200,000 Mcf in order to begin addressing the known shortfall. AmerenIP states that 200,000 Mcf is 2.5% of the working gas volume in Hillsboro, which it claims is within the typical range for gas losses by Illinois gas utilities. Further, AIU claims it was able to confirm in 2007 that 200,000 Mcf was a conservative and reasonable estimate to use to address gas losses in the reservoir.

Staff's view that AIU's current proposal conflicts with data reviewed in a prior rate case is also incorrect, AIU argues. Staff believes that the 5.8 Bcf adjustment contained in the 2004 Hillsboro Report overlaps with the 1.1 Bcf adjustment under instant review. However, AIU asserts that the metering errors described in the 2004 gas rate case were corrected in the fall of 1999. AIU says the inventory correction volume of 5.8 Bcf quantified the effects of the accumulated metering errors from 1993 to 1999 and was reinjected into Hillsboro in 2004 and 2005. After 2000, as a result of Peterson's 1999 Metering Study, AIU claims the method of operating the storage field changed so that injection meter error was eliminated. Therefore, for modeling purposes and to allocate the 5.8 Bcf correction back in time, AIU maintains that only data from the 1994 to 1999 injection seasons were modified in the database. AIU says the analysis of the metering error that AmerenIP performed in 2007 after comparing the newly installed ultrasonic meters to the existing metering led AmerenIP to conclude that the leaking valve induced error began during 2000. AIU insists that the 1.1 Bcf correction was only applied beginning with the 2000 to 2001 withdraw season and ending with the 2006 to 2007 withdraw season. AIU maintains that there is no overlap of the requested adjustments, as this case requests inventory corrections for the period 2000 to 2003. At Hillsboro, AIU relates that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis utilizing hysteresis techniques. However, AIU believes other information is available to support the proposed inventory adjustment.

AIU avers that Mr. Lounsberry's third concern, that certain assumptions within AmerenIP's calculations are not robust, is also unfounded. AIU says Mr. Lounsberry laid out 5 specific concerns with the gas-volume calculation:

1. Valve leakage could have worsened over time.
2. Other errors could have caused the differences.
3. The 2.75 % error was used even when valve was fully opened.
4. Concern about only using the January 24 to February 25 time period and then extrapolating over 7 years.
5. All meters in series will show a percent difference.

AIU claims it has addressed all five concerns. AIU says the first concern makes a faulty implicit assumption: that the valve leak had worsened over time, and that the calculation thus overstated initial volumes that were not measured. AIU says it has no indication that the leak did worsen over time. Therefore, AIU concludes the 2000 start point for the full leak is an appropriate assumption. In addition, AIU asserts that it would be difficult to identify when or at what rate such worsening of the leak would occur.

AIU claims the second concern, that there are other potential causes for the observed measurement error/gas-volume discrepancy, is unsubstantiated. Staff suggests that AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. AmerenIP says that although it can not determine that —all" of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP reasonably believes that the leaking valve or the orifice plates were the dominant sources for the observed errors. Staff further suggests that the metering review was incomplete, but AIU says it offers no specifics as to what should have been reviewed.

According to AIU, there is no justification for Mr. Lounsberry's position that the reference to volumetric variance resulting from pressure and temperature variance —confirms" the possibility of —significant" variances in measured values. AIU says the differences described for the temperature and pressure transmitters were from the period that comparison testing was conducted using the new ultrasonic meters and in-place South Pipeline (—SPL") orifice metering on February 21-22, 2007. AIU claims the only data that exists on a daily basis from which any volumetric error can be calculated is the daily SPL withdrawal numbers. The correction volume, AIU states, was calculated based on information available to make the correction. AIU adds that the referenced transmitters are calibrated each fall prior to the withdrawal season and adjusted as needed so any variances in measured values are minor.

Mr. Lounsberry's third concern, that the 2.75% error rate for a fully-open valve is unexpectedly high, is, in AIU's view, also unwarranted. AIU claims the error-rate calculation was based on an analysis of actual data by AmerenIP. AmerenIP says it determined the 2.75% error by comparing actual daily flows from both the SPL and North Pipeline (—NPL") orifice runs, adjusted for the correction to the NPL flows for orifice installation problem and then correcting the SPL flow so that the daily sum of the adjusted NPL and corrected SPL flows matched the ultrasonic meter daily volume. AIU insists that the correction method made use of the best information available. AIU says the historical daily 2000 to 2007 volumetric data was available for the NPL and the SPL, but not by primary or primary and secondary run volumes. According to AIU, it would therefore be impractical to try to apply separate primary and secondary run corrections. AIU claims that based on the hourly test at 1600 Mcf/hour, with both primary and secondary open, the accumulated volume error percentage was 2.246%, and not negligible. AIU states that the flow exceeding 35,000 Mcf/day SPL correction of 2.75%, derived from correcting the daily NPL and SPL volumes to ultrasonic meter volumes, is comparable to the test measured error over one hour of 2.246%.

AIU says it attempted to identify all causes for the differences between the SPL orifice volumes and the ultrasonic meter volume. AIU insists the testing performed was thorough and resulted in the leaking valve being identified as the most significant problem that resulted in the differences in measured volumes. AIU also states that real time testing requires the field to cease normal withdrawal operations and requires operators to modify flow rates, open and close valves, and verify readings at several points along the data communications path. When testing the SPL meters, AIU says withdrawals to the NPL are stopped, and the flow rates are adjusted for testing which impacts the gas dispatch function. AmerenIP concluded that it had identified the cause of the measurement error and it would be unreasonable to further disrupt the dispatch function and tie up operators for long periods of time to determine the source of errors beyond what was performed. In AIU's view, Mr. Lounsberry‘s theoretical concerns ignore AmerenIP‘s reasoned and reasonable approach to the leak investigation and calculations.

According to AIU, Mr. Lounsberry‘s fourth concern, that the leak measurements were extrapolated from data gathered during a one-month review, overlooks the fact that the review period could not have begun sooner, nor been fair and representative of the leak after February 20th. AIU indicates the ultrasonic meters at Hillsboro were placed into service on January 23, 2007, so a comparative analysis could not have been started sooner than that date. On February 20th, AIU says the NPL plates were installed correctly and the SPL secondary run problem was discovered and isolated. AIU claims any information collected after corrective action was completed would not be useful for determining prior period corrections. In AIU's view, the review period selected represents the best available information regarding the measurement error. AIU believes that since the information from the review period was the best information available, it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

AIU argues that Mr. Lounsberry‘s position, that conditions during the 1-month review period may not have mirrored conditions during the rest of the 7-year adjustment period, does not support a conclusion that the estimate of the leak was unreasonable. According to AIU, there were no physical changes made to the piping on the SPL meter runs from 1999 to 2007. AIU says the orifice plates in both runs have not been changed, nor has the computation method for volumes changed so the measurement system for the SPL orifice meter runs over the prior 7 years is identical to the system used during the month for the correction. AIU claims the test included flow rates over the entire flow range simulating flowing conditions. The actual flows, AIU asserts, were matched daily back to the tested flows to come up with the error amounts. AIU contends there is no reason to believe that circumstances did not remain reasonably similar throughout the 7 year time period. Given that there were no significant changes, AIU believes its extrapolation was appropriate.

Mr. Lounsberry‘s fifth concern, that meters connected in series will typically exhibit some variance, is de minimis, according to AIU. AIU acknowledges that there will be variances between meters. AIU believes, however, that the impact of any such variances on the measurement error calculation will be minimal. AIU says the measurement error calculation is an estimate. AIU states that the ultrasonic meter measurement uncertainty is much less than volumes determined by the orifice meter system. AIU say it has high confidence in the computed volumes from the ultrasonic meters and believes that the variances, and their impact on measurement error calculation, would not be significant.

In AIU's view, Mr. Lounsberry's reason for rejecting the current base gas adjustment, that AmerenIP should have identified the valve failure more swiftly, is an unfair criticism of AmerenIP's approach to identifying and correcting system issues. Mr. Lounsberry's criticisms of the operation of Hillsboro relate to events that took place prior to 2004. AIU insists that since 2004, AmerenIP has undertaken a number of steps to address these events. AmerenIP says it only discovered the leaking valve after the ultrasonic meter was installed, and AmerenIP compared its measurements with the existing master metering total withdrawal volumes. AmerenIP claims the leak was too small to be detected on the orifice recording chart or register on the station control system and noise through the leaking valve was not observed because of noise generated by the flow control valve down stream of the leaking valve masked any noise from the run change valve. AmerenIP also asserts that the annual maintenance performed on the valve indicated that the pneumatic operator rotated full open and back to full closed position each fall prior to withdrawal season. AmerenIP maintains that it had no reason to suspect that gas was by-passing the closed run changer valve until it compared the volume through the ultrasonic meter placed into service in January 2007.

Mr. Lounsberry asserts, however, that the past problems at Hillsboro are still relevant to this proceeding because he believes they relate to the issue of the discovery of the leaking valve problem in 2000. Mr. Lounsberry believes that AmerenIP should have discovered the leak before 2007, given the focus on issues at Hillsboro in 2004, and that AmerenIP's failure to review or discover that problem at that time is a reflection on how AmerenIP operated its storage fields during the time period. AIU believes this concern is mistaken. AIU states that AmerenIP made annual checks on the valve in question, but the purpose of these checks was to verify that the valve opened and closed at the appropriate differential pressure signals across the primary orifice run. Given the nature of the leak, AIU insists that it is unlikely the leak could have been discovered sooner, even during the investigations of issues at Hillsboro in 2004. AIU says AmerenIP personnel made no observations that gas was leaking from the valve when it was in the closed position until after the ultrasonic meter was installed and a difference was observed in the calculated volumes. In AIU's view, the failure to find the leak was not related to problems at Hillsboro, and the fact that there were past investigations does not mean the leak would have been found any sooner. AIU also maintains that AmerenIP would have had to discover the leak before April of 2004 to have made any difference in the adjustment sought in this proceeding. AIU says the estimated errors using AmerenIP's method did not affect the base gas values after April of 2004.

According to AIU, Mr. Lounsberry's suggestion that AmerenIP could have identified the valve leak through a ―block and bleed" test is unfounded. AIU says the valve manufacturer's manual makes no mention of performing the procedure in order to verify the valve seats are seating properly; the manual does not mentioned this is a procedure that should be performed as ongoing maintenance of the valve; and the procedure is not a common practice to perform. AIU contends the suggestion that AmerenIP should have performed this procedure reflects the benefit of hindsight, but AmerenIP had no reason to discover the leak prior to the installation of the ultrasonic meter. AIU adds that the consultant (Peterson) who performed the comprehensive 1999 metering study at Hillsboro did not suggest conducting such a test, which further demonstrates that this is not a common practice.

b. Staff's Position

Mr. Lounsberry opposes AIU's attempt to increase the base gas inventory value at the Hillsboro field by $2,841,000. He has four reasons for disputing AIU's request. First, Mr. Lounsberry does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Second, he determines that AIU had inadequate support for the assigned value. Third, Mr. Lounsberry questions the validity of certain assumptions that AIU made as part of the calculation. Finally, he notes that given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro field, AmerenIP should have, as part of its overall investigation of the various problems it has experienced at Hillsboro, conducted a review of the integrity of the valve at a much sooner date and, as such, AmerenIP should have never found itself in this position.

AIU notes that as a result of new metering installed at Hillsboro storage field in 2007, AmerenIP discovered a discrepancy between the new metering and the original metering used to measure the volume of gas withdrawn from the Hillsboro field. AmerenIP conducted a series of tests that demonstrated there was a leak in the valve that separated the primary and secondary metering runs in the original metering set that measured gas flowing to the south of the Hillsboro field. AmerenIP claimed that this leaking valve allowed gas to pass undetected and unmeasured through the secondary metering run. AmerenIP selected the time period of 2000 to 2007 to reflect the measurement error.

Staff says AmerenIP's assumed timing for this metering error impacts the recoverable base gas valuation in 2001 to 2004 because it assumed this metering error occurred in addition to the metering error that was at issue in last rate case, Docket No. 04-0476. AmerenIP contends that both errors understated the withdrawals from the Hillsboro field, meaning that it had withdrawn gas from the Hillsboro field in excess of those levels that it maintained in its top gas volumes and had unknowingly withdrawn gas from its recoverable base gas inventory.

Mr. Lounsberry takes issue with AmerenIP's logic in selecting the starting date for the valve leak. In particular, he notes that AmerenIP assumed the leak existed for the period 2000-2007. Staff says AmerenIP's selection of that time period was based upon the fact that the valve was rebuilt in 1993 and the leak was discovered in 2007. Since the exact date of the leakage could not be determined by AmerenIP, Staff says it decided to go back to half the amount of time since the valve was installed. Staff believes that AmerenIP's decision regarding the timing of the valve leak was pure speculation and is not sufficient basis to support the just and reasonable threshold for AmerenIP‘s request to increase the recoverable base gas costs at Hillsboro.

Mr. Lounsberry also expresses a concern regarding the lack of support that AmerenIP had for the volumes it calculated. Specifically, he notes two distinct concerns. First, AmerenIP‘s inconsistent operation of the Hillsboro storage field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. Second, AIU's current proposal is at odds with the information it provided in the prior rate case regarding the shortfall that existed at the Hillsboro field as of November 30, 2003, as detailed in the 2004 Hillsboro Report.

Staff asserts that AmerenIP‘s inconsistent operation of the Hillsboro field creates a situation where it is not possible to reasonably use reservoir information to support any adjustments. This viewpoint, Staff claims, was also shared by AmerenIP personnel in a November 20, 2006, report noting that in September 2004 AmerenIP had just completed a 2.2 Bcf addition to Hillsboro‘s inventory that completed AmerenIP‘s 3-year replacement (2003-2005) of the 5.8 Bcf inventory shortfall that IP found at the Hillsboro field in 2003. According to Staff, this report indicated that, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. Staff says AmerenIP personnel estimated that after 3 years of cycling the reservoir at a constant working gas volume, the reservoir would stabilize and the hysteresis curve will be helpful in quantifying gas loss volumes.

Mr. Lounsberry states that his understanding of this report was to represent that AmerenIP had no reliable support for adding any gas to the Hillsboro field because the field‘s reservoir information changed too frequently to be used to determine any values. Staff claims this also means that AIU's request is speculative and that it can not support the just and reasonableness of its proposal. In response to Mr. Lounsberry‘s concerns, AIU notes that AmerenIP used pressure and volume data to support the measurement error calculation and that it considered this data as sufficient to support the adjustment. AIU also notes that while Staff had previously questioned the methodology and conclusions on reservoir engineering studies in many previous AmerenIP cases, Staff never questioned the validity of the wellhead pressure measurement that it claims supports its request.

Aside from its previous discussion regarding the lack of reliable reservoir data, Mr. Lounsberry provided two additional reasons to dispute AIU‘s statements. First, while AIU's statement that Staff never disputed AIU‘s use or calculation of wellhead pressure measurement in prior cases is accurate, Staff did question AmerenIP‘s methodology and conclusions on reservoir engineering studies in those cases. Staff says the fact that AmerenIP, in the prior cases, did not rely solely upon the wellhead pressure measurement information to support its position suggests the other methodologies that AmerenIP employed in those proceedings were deemed by it to be superior to the calculations that AmerenIP provided in the instant proceeding that consider only one measure, wellhead pressure.

Second, Mr. Lounsberry understands that there are many methods available to AmerenIP to determine if a particular storage field has an inventory shortfall. Staff says a comprehensive review should be done to support an inventory shortfall; reliance should not just be placed on one measure whose information may or may not be consistent with other measures available to the utility. Aside from Mr. Lounsberry's concern regarding AmerenIP's calculations, AmerenIP also notes that it intends to conduct a detailed reservoir engineering study after the end of the 2008 injection season. AmerenIP indicates that this study was not performed in 2005 because it was of the opinion that there was insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate.

Mr. Lounsberry does not dispute AmerenIP's need to conduct the study, but believes that AmerenIP's statement that there is insufficient information available to form a reliable conclusion as to whether any further adjustment to the original 5.8 Bcf correction was appropriate is contrary to its claim that AmerenIP has valid support for the addition of about 1.1 Bcf of gas that would increase the base gas valuation of Hillsboro by $2,841,000. Staff argues that the information is either available or it is not; AIU can not have it both ways. Mr. Lounsberry believes that AmerenIP does not currently have any reliable information to support the 1.1 Bcf addition.

Mr. Lounsberry expresses concern that AmerenIP had to make a number of assumptions when it calculated the measurement error volumes associated with the leaking valve at the Hillsboro field. He also asserts that AmerenIP's situation does not lend itself to provide a good basis to extrapolate out the measurement errors it found over a 7-year period. In particular, Mr. Lounsberry identified 5 areas of concern: valve leakage could have worsened over time; other errors could have existed; a 2.75% error existed even when valve was fully open; using one month to extrapolate out 7 years; and all meters in series show some difference in readings.

Mr. Lounsberry expresses concern that AmerenIP assumed the correction values it calculated could be applied for the whole period that AmerenIP estimates the measurement error took place. Staff asserts that it is possible that the valve leak worsened over time, meaning that AmerenIP's calculation overstates the initial volumes that were not measured. AIU's response to this concern is that it had no indication that the leak worsened over time. AIU also notes that it would be difficult to identify when such worsening of the leak would occur or at what rate the worsening would occur. Staff agrees that given the lack of data to support when the valve leak started or for how long the leak existed, it would be virtually impossible for AmerenIP to determine if or when such worsening of the valve leak would occur or at what rate the worsening would occur. Staff claims AIU has not stopped to consider the reasonableness of its assumption regarding the valve leak. Staff asserts that AmerenIP simply found a value leak and then blindly assigned it to the time period that AmerenIP assumed the error occurred.

According to Staff, AmerenIP assumed that all of the errors it found were either caused by the leaking valve or the incorrectly installed orifice plate. Staff suggests that on an orifice meter, there are multiple items that can cause error, such as a pressure or temperature probe that is out of calibration. Staff contends it is not clear if AmerenIP eliminated all of the potential causes of measurement error when it performed its review. Staff says that if AmerenIP did not eliminate all potential causes for the error, then it could have under or overstated its measurement error estimate. AIU responds that, while it can not determine that ―all‖ of the errors observed were either caused by the leaking valve or due to the orifice plates, AmerenIP believes the leaking valves or the orifice plate were the dominate sources for the observed errors. AmerenIP also indicated that the pressure and temperature used for the orifice measurement relative to the measurements used for the ultrasonic meters would decrease the volumetric differences between the orifice measurement and the ultrasonic measured values.

Staff says that AIU‘s reference to the decrease in volumetric differences between orifice measurement and ultrasonic measurement due to the pressure and temperature variances between the two metering sets confirms Staff‘s point. Staff does not know the exact time period AmerenIP reviewed to make its statement, but the basic concept is that, depending on the frequency that AmerenIP calibrated its temperature and pressure probes and how much variance those probes could develop, the measurement calculation will differ over time, creating a situation where the volume differences either decreased or increased. Staff argues that given AmerenIP‘s decision to extrapolate out the measurement impact it calculated over a 7-year period, any variance in measurement can be significant and it does not appear that AmerenIP attempted to account or identify the reasons for those errors.

Staff also expresses concern over the fact that AmerenIP calculated an error of 2.75% even when the valve was fully open. Staff says that since AmerenIP claimed the reason for the measurement error was due to the leaking valve, it would not expect a fully open valve with a leaking seal to create a measurement error of that magnitude. Staff‘s understanding of AmerenIP‘s explanation for the measurement error is that some quantity of gas passed through the valve that the secondary metering run could not measure because the amount was too small for the meter to pick up. Staff claims that once the valve is fully open, the secondary metering run is measuring a considerable amount of gas that should account for all gas volumes whether the valve is leaking or not. Staff contends that the measurement error under that circumstance should be negligible, not a significant amount like 2.75%.

AIU responds by indicating that the analysis of the 2.75% error was determined from actual daily flows from both of the orifice runs. AmerenIP also indicates that based on an hourly test flow rate of 1600 Mcf/hour, with both primary and secondary metering runs open, the accumulated error percentage was 2.246% and not negligible. Therefore, AmerenIP believe the assumption that for flows exceeding 35,000 Mcf/day there is a 2.75% error is comparable to the error shown for just one point in time.

Staff does not dispute AmerenIP‘s calculation of the error percentage, the fact that an error exists lends support to its second concern that AmerenIP had not identified all of the causes of the measurement error. According to Staff, a 2.75% variance between two sets of meters is considerable and AmerenIP should have attempted to determine the cause of this error beyond the general conclusion that the error is a result of the valve leak. AIU responds by noting that when it was calculating its measurement errors, it was disrupting the manner in which the Hillsboro field normally operated. AIU states that AmerenIP had identified the cause of the measurement error and it would be unreasonable to disrupt the dispatch function further and tie up operators for long periods of time to determine the source of errors beyond what was performed. Staff also does not dispute that AmerenIP was likely disrupting the manner that the Hillsboro storage field operated when it was conducting various measurement tests. Staff maintains, however, that AmerenIP found an almost 3% error in a situation where the error reading should have been negligible and AmerenIP did not bother to investigate the cause of the problem further.

Staff also argues that it is not possible that all of the circumstances occurring for that one month were exactly the same for all of the months over the prior 7 years. In other words, Staff claims AmerenIP had a snapshot of what occurred, but has no way to determine if the circumstances that occurred during that month were identical to the circumstances for the prior 7 years. AIU responds that the selected review period represented the best available information regarding the measurement error. Since it was the best information available, AIU claims that it was appropriate to use that information as a basis for estimating the measurement error for 2000-2007.

Staff states that, in theory, two meters placed in series would show no variance; however, the reality is that all meters have some variance between each other. Staff indicates this could occur because no meter is perfect and meter manufacturers do not guarantee absolute accuracy with their meters. Staff says there is usually an accuracy range provided, such as plus or minus 1%. Therefore, Staff indicates that two meters in series will likely not correlate directly to each other. As a result, Staff expressed a concern that a small portion of AmerenIP‘s correction it is attempting to fix could, in reality, not be a measurement error.

In its Reply Brief, Staff notes that AmerenIP argues that it is not required to use any particular type of study to demonstrate prudence, and that no one has challenged the two forms of input data that AmerenIP is using to support measurement error correction, namely pressure and inventory. According to Staff, AmerenIP indicates that, contrary to Staff‘s concern that AmerenIP could have used superior methodologies, it used valid reservoir engineering techniques to determine gas loss. Staff disagrees. Staff contends it has not directed AmerenIP to make use of any specific type of analysis to support the adjustments. Staff claims it pointed out that AmerenIP had used in its prior rate case a reservoir simulator model that its witness from that proceeding indicated was superior to any static method of predicting reservoir behavior. Staff expresses concern that, given the time and money spent on developing this model, Staff would have expected AmerenIP to make use of the model had it been available.

Staff says that contrary to AIU's claims, this is not a directive from Staff to make use of a specific analysis. Instead, Staff indicates that AmerenIP's analysis failed to support its request. Staff does not agree that the reservoir engineering techniques AmerenIP used were valid under its current circumstances.

c. Commission Conclusion

AIU proposes the addition of $2,841,000 to the Hillsboro base gas account, an increase in rate base. AIU claims the addition is necessary to account for base gas lost through a valve leak and is necessary to maintain the deliverability of the Hillsboro Storage Field. AIU argues that AmerenIP used the best techniques available to estimate the lost gas and that it should be allowed to include the base gas in rate base.

Staff objects to AIU's proposal to include the additional base gas in rate base. Staff does not consider AIU's logic in determining the timing of the metering error at Hillsboro during the years 2001 to 2004 valid. Staff contends that AIU has not adequately supported the amount it seeks to include in rate base. Staff questions the validity of certain assumptions that AIU made as part of the calculation. Given the history and magnitude of the problems that AmerenIP has experienced at the Hillsboro storage field, Staff asserts that as part of its overall investigation of the problems at Hillsboro, AmerenIP should have conducted a review of the integrity of the valve at an earlier date.

The Commission observes that this issue is strikingly similar to the issue decided immediately above. In both instances, AIU asserts that there has been lost base gas, has estimated the volume of missing gas, and requests authorization to include the additional base gas in rate base. Also in both instances, Mr. Lounsberry objects to AIU's request. Mr. Lounsberry again insists, among other things, that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost base gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AmerenIP failed to adequately demonstrate that its estimate of the lost base gas is reasonable. As a result, the Commission adopts Staff's recommendation and AIU's request to include the additional base gas in rate base is denied. In the Commission's view, this decision regarding lost gas at Hillsboro is consistent with, and is required by, the appellate court decision discussed earlier in this Order.

D. Approved Rate Bases

Based on the determinations made above, the rate bases for AIU's respective service territories are approved as shown below and in the Appendices attached hereto.

	AmerenCILCO	AmerenCIPS	AmerenIP
Electric	$240,625,000	$443,743,000	$1,254,459,000
Gas	$183,734,000	$181,735,000	$518,857,000

V. OPERATING REVENUES AND EXPENSES

A. Introduction

Schedules showing the operating revenues, expenses, and income at present and recommended rates for the test year ending December 31, 2006, were presented by AIU and Staff.

B. Resolved Issues

1. Annualized Labor and Pro Forma Wage Increases

Staff witness Ebrey recommends adjusting annualized labor expense to reflect a 3% wage increase effective July 1, 2007, based on her assessment of actual wage increases approved in December 2007. AIU agrees with this adjustment.

Ms. Ebrey also recommends disallowing wage increases for management employees projected for April 1, 2008. AIU responds that the wages already increased to slightly beyond the estimated levels as of the time of the filing of rebuttal testimony, thus the increases are known and measurable. In its rebuttal testimony, Staff accepts the AIU proposed rebuttal labor adjustment for management employees in all six rate cases. The Commission finds Staff's proposed adjustment to increase labor expense to reflect the July 1, 2007, wage increase reasonable and is hereby adopted. The Commission also finds AIU's proposal to reflect the April 1, 2008, management wage increase reasonable and is hereby adopted.

2. Injuries and Damages Expense

Rather accepting AIU's proposal for calculating injuries and damages expenses, Staff proposes using a five year average in calculating the expenses for AmerenCILCO's, AmerenCIPS', and AmerenIP's gas operations. For these five utility operations, AIU does not object to Staff's proposed methodology. The Commission finds this approach to be reasonable and it is hereby approved for the five utility operations identified. The issue of how injuries and damages expenses should be calculated for AmerenIP's electric operations is address later in this Order.

3. Employee Benefits Expense

Staff proposes an adjustment to AIU's Employee Benefits Expense. For purposes of this proceeding, AIU accepts Staff's proposed adjustment to Employee Benefits Expense. The Commission finds Staff's proposed adjustment to the employee benefits expense reasonable and it is hereby approved.

4. Reliability Audit

With regard to the Liberty reliability audit performed for AIU, Staff witness Ebrey proposes to only allow the maximum estimated price of Liberty, $2,897,880, and the actual rental of office space for 12 months per the lease agreement of $29,290, allocated to each electric utility consistent with AIU's proposal. AIU accepts Staff's proposed adjustment. The Commission finds Staff's proposed adjustment to the reliability audit expense reasonable and it is hereby approved.

5. Storm Costs

Staff witness Everson recommended use of a separate subaccount to track costs associated with storm restoration. After reviewing AIU's responsive testimony, Ms. Everson withdrew her recommendation. The Commission finds that there is no longer a contested issue related to storm costs and the Commission takes no action.

6. Interest on Customer Deposits

Staff witness Everson proposes using a 3.5% rate as the interest rate on customer deposits, which was accepted by AIU. AIU believes the adjustment should be reflected as an adjustment to Customer Accounts Expense, to which Staff does not object. The Commission finds the proposed treatment of customer deposits to which AIU and Staff agree to be reasonable and it is hereby approved.

7. Accounts 856, 863, 874, and 887

In direct testimony, Staff witness Lounsberry raises concerns regarding Accounts 856, 863, 874, and 887. In its rebuttal, AIU explains the nature or circumstances surrounding the costs (in particular, that costs shift between the AIU transportation and distribution Operations and Maintenance ("O&M") accounts from year to year). Mr. Lounsberry found AIU's explanation acceptable and withdrew his proposed adjustment.

8. Advertising Expense

Staff proposes an adjustment to AIU's proposed level of Advertising Expenses, which AIU accepts. The Commission finds Staff's proposed adjustment to advertising expenses to be reasonable and it is hereby approved.

9. Industry Association Dues Expense

Staff proposes and adjustment AIU's electric utilities' industry association dues, which AIU accepts. The Commission finds Staff's proposed adjustment to AIU's electric industry association dues expense reasonable and it is hereby approved.

10. Vegetation Management/Tree Trimming

In response to AG/CUB witness Effron's direct testimony, AmerenIP agrees that its tree trimming expenses should be reduced by $1,932,000. Although Mr. Effron originally proposed an adjustment to AmerenCIPS' pro forma tree trimming expenses, after reviewing Mr. Stafford's rebuttal testimony explaining why no such adjustment was necessary, Mr. Effron withdrew his proposed adjustment. The Commission finds that the agreed adjustment to AmerenIP's tree trimming expense is reasonable it is hereby approved.

11. Midwest Independent System Operator Expenses

AmerenIP agrees to the proposal to eliminate from its delivery service revenue requirement $1,037,000 of payments to the Midwest Independent System Operator, which AmerenIP charged to Account 928 "Regulatory Commission Expenses" in 2006. The Commission finds the proposal to adjust Account 928 for AmerenIP to be reasonable and it is hereby approved.

12. Retired Production Worker Pension and Medical

In his direct testimony, Staff witness Lazare expresses concern about whether pension and health care costs for AIU retirees who worked at production facilities that have since been divested from AIU should be included in test year A&G expenses. AIU accepts Staff's proposed adjustments. The Commission finds Staff's proposed adjustment related to the retired production worker pension and medical expense to be reasonable and it is hereby approved.

13. Test Year NESC Violation Correction Costs

In response to Staff's concerns regarding the costs to correct National Electrical Safety Code ("NESC") issues during the test year, AIU agrees to track the costs of repair or replacement of identified down guy, overhead guy, and double-cross arms at affected railroad or interstate highways. AIU agrees to replace those railroad or interstate highway crossings that have only a single cross-arm, but under new NESC standards should now have a double-cross arm. Additionally, AIU agrees to bear all 2006 test year costs associated with the remediation of NESC violations. The Commission finds it appropriate for AIU to track the costs of repair or replacement of facilities that were originally constructed in violation of NESC to be reasonable. Additionally, the Commission agrees that AIU should not recover from ratepayers the costs incurred during the test year for these types of activities.

C. Contested Issues

1. AMS Charges

a. AIU's Position

AIU argues that accepting Staff's proposed adjustment of $48.3 million representing AMS charges would pose a significant threat to AIU's financial health and that it is entitled to recover the charges AMS assesses on AIU for essential utility services. AIU alleges that Staff's adjustment arises from its invention of a new allocator that Staff applies to the total AMS charges assessed on all Ameren subsidiaries. AIU submits that Staff's allocator is based on an assumption that has never been tested, proven, or used in any jurisdiction and the allocator presupposes that all subsidiaries will consume services from a common service company in direct proportion to their size, as measured by the simple arithmetic average of three metrics: total assets, total employees and non-fuel O&M. AIU avers that should the Commission accept this adjustment, AIU will under-recover its costs by $48 million. Were this to happen, AIU claims it would be forced to make cuts in service in order to maintain its financial condition.

AIU points out that in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission directed AIU to provide, in its next delivery service case, a study regarding the services and related costs that AMS provides to AIU. AIU submits that in compliance with the Commission's directive, it hired a consulting firm, Concentric, to prepare a study of the services and related costs that AMS provides to AIU. AIU says the Concentric study benchmarks the costs of specific services provided by AMS to AIU. AIU notes that the services studied include finance, information technology, human resources, procurement, legal, government affairs, and corporate communications, which account for approximately 60% of total AMS expenses charged to AIU. AIU states that for each of the services provided by AMS, the total cost of providing the service was compared to both other utilities and to non-utility companies. According to AIU, AMS costs for services compared favorably to the peer companies.

AIU explains that during the review of AMS costs allocated to AIU, Concentric employed a cost causation standard to assess the reasonableness of the allocated costs, and under cost causation principles, the standard of reasonableness was whether the costs allocated to each of the individual utilities was representative of the benefits realized by each company. AIU further explains that AMS costs are recorded in various SRs. Each SR relates to a specific scope of work by an organizational unit within AMS. AIU notes that when created, the SR must consist of a project name, a description of the work to be performed, and the allocation factor to be used to distribute the costs assigned to each SR. The appropriate allocation factor is determined from the list of available allocators set forth in the General Services Agreement ("GSA"). The SR is signed off on by representatives of each Ameren subsidiary which will benefit from the work performed and a representative of AMS.

AIU argues that it has complied with the Commission's directive in the last proceeding, that it has submitted substantial evidence demonstrating that its A&G costs in general, and AMS charges in particular, are reasonable, consistent with those incurred by comparable entities in the market, and should be approved as proposed.

b. Staff's Position

Staff argues AIU proposes a disproportionate allocation of AMS costs to AIU without providing a reasonable explanation or adequate support. According to Staff, there are systematic problems with the allocation of AMS costs that not only support Staff's proposed $48.3 million reduction in these costs, but further call into question the full amount that AIU proposes to recover from ratepayers. Staff submits that its proposed adjustment of $48.3 million would make the allocation of AMS charges to AIU consistent with the relative size of each company.

Staff points out that AMS costs are a significant portion of test year costs. Staff notes that AIU seeks to recover a total of $213.7 million in AMS costs from ratepayers for the test year. Staff further notes that the Commission has expressed its ongoing concern about the recovery of these costs from ratepayers, and Staff submits that AIU has yet to satisfactorily address these concerns. Staff further opines that a review of the evidence in this case shows that there are fundamental problems with the way AMS costs are allocated to AIU.

Staff argues that the first step in developing its adjustment is to determine what would be an appropriate allocation of AMS costs to AIU based on the relative size of each company. According to Staff, there are three measures to determine the relative size of a company: assets, non-fuel O&M, and number of employees. Staff notes that assets are the investments on which a company seeks to earn a return. Staff contends the level of assets is an important determinant of their level of business success. Staff notes that non-fuel O&M reflects expenses incurred to operate a company, and Staff submits that the levels of these costs provide an indicator of the relative costs of operating a company. As to number of employees, Staff suggests a larger company will entail more activity and require more employees to ensure that tasks are performed.

Staff witness Lazare found that AIU accounts for 34.0% of assets; 33.9% of employees; and 36.8% of non-fuel O&M expenses for Ameren as a whole. Staff submits that with no specific evidence to indicate that any of these measures is more relevant than any other, the simple average of these percentages is used to find that AIU constitutes 34.9% of Ameren on a size basis. Since AMS charged a total of $473.6 million to all Ameren subsidiaries in 2006, Staff suggests that the share that AIU should receive based on its size is 34.9% of that total or $165.4 million. Staff further argues that since AIU proposes to allocate $213.7 million of AMS costs to AIU for the test year, an adjustment of $48.3 million to AMS costs allocated to AIU is appropriate.

Staff points out that AIU has a responsibility in this case to demonstrate that it received a reasonable share of AMS costs, particularly in light of the Commission's concern in Docket Nos. 06-0070/06-00071/06-0072 (Cons.) about the allocation relative to other Ameren subsidiaries. However, Staff suggests that AIU failed to explain why it receives a disproportionate share of these costs relative to its size. Therefore, Mr. Lazare proposes an adjustment to remove the "excess" share of AMS costs.

Staff argues Mr. Lazare‘s proposed adjustment represents a conservative reduction in AIU's proposed revenue requirement. Staff states further that the evidence reveals fundamental problems with the SRs, which are the building blocks for the allocation of AMS costs among Ameren subsidiaries. The process by which these SRs are allocated to AIU, Staff argues, is riddled with errors, and the resulting allocations of AMS costs as a whole are called into question.

Staff complains that based upon its review, AIU witness Adams identified only three SRs that were inaccurately recorded, resulting in an under allocation of $23,869 to AIU by AMS. Staff is not comfortable with Mr. Adams' conclusion that the services described and allocations for each SR are reasonable. Staff suggests that the focus of this case should be on AIU's failure to support its disproportionate allocation of AMS costs. Staff posits that should AIU succeed in changing the subject to focus on a small number of SRs, AIU and other utilities will be encouraged to provide even less support for their ratemaking proposals in the future.

In addition, Staff disagrees with AIU that its bench mark study justifies AMS costs allocated to AIU. Staff argues the study failed to answer a basic issue raised by the Commission in its Order on Rehearing in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission in that proceeding stated that there was insufficient evidence to indicate that AIU received a reasonable allocation of AMS costs relative to other Ameren affiliates. This statement emphasizes, according to Staff, the need to examine AMS costs for all Ameren companies, not just those directly regulated by the Commission. Staff suggests that the Commission appropriately recognized that the fairness of the allocation of common AMS costs to one group of Ameren companies can only be assessed when comparable information is provided on the allocation received by others. Staff notes that AMS costs are shared by all Ameren subsidiaries, and that it is essential for Ameren to show that the allocations to AIU are reasonable compared with other Ameren subsidiaries.

According to Staff, the Commission must assess the reasonableness of all costs passed along to AIU ratepayers, including AMS costs. Staff suggests however, that the study performed by Mr. Adams fails to satisfy this requirement. Staff notes that while Mr. Adams identifies five findings he made from the study in his rebuttal testimony, none of these findings directly discuss how AMS costs are allocated to other Ameren subsidiaries. Staff suggests further that the study only examined the A&G component of AMS costs, while AIU is additionally requesting recovery of AMS charges that are outside the A&G area.

c. Commission Conclusion

As the parties are aware, the Commission takes seriously its obligation to assure that affiliate costs are not improperly passed along to utility ratepayers. AIU and AMS operate under the GSA previously approved by the Commission. The GSA calls for direct assignment of AMS costs where possible. In addition, the GSA contains numerous allocation factors that are to be used when costs can not be directly assigned. While AIU is not necessarily entitled to recover from ratepayers all AMS costs allocated pursuant to the GSA, the GSA is intended to assist the Commission in ensuring that AIU and ratepayers are not assessed improper costs by affiliates.

Rather than rely upon direct assignment and the numerous allocation factors contained in the GSA, Staff assumes that all AMS costs should be allocated among affiliated entities on the basis of their relative size. That assumption is inconsistent with the GSA approved by the Commission and, in the Commission's view, is not a reasonable assumption. Under Staff's proposal, for example, assuming that AMS provides services to AIU to prepare and litigate a rate case, 65% of such costs would be allocated to unregulated affiliates. Unfortunately, it is easy for the Commission to envision numerous situations where AMS costs would not properly be allocated among Ameren companies based upon the relative size of the companies. The Commission can envision situations where costs would be improperly allocated to AIU as well as situations where costs would be improperly allocated to unregulated affiliates. The Commission concludes that Staff's single allocator is too simplistic and does not produce reasonable or appropriate results.

While not perfect, the Commission finds the Concentric study of AMS charges to be helpful. The Commission believes that the testimony of Mr. Adams and the Concentric study demonstrate that test year level of AMS costs assessed to AIU are reasonable. In summary, the Commission concludes that Staff's proposal should be rejected and that the record supports a finding that the AMS costs assigned to AIU are reasonable and should be included in operating expenses.

In its Brief on Exceptions, Staff complains that the conclusion in the Proposed Order did not specifically address each and every alleged flaw it identified in AIU's AMS cost analysis. To be clear, the Commission considered each aspect of Staff's arguments, and the Commission does not believe that AIU's evidence is perfect. The Commission concludes, however, that despite any flaws in the evidence presented by AIU, it is superior to Staff's proposal for establishing the amount of AMS costs that should be reflected in rates. Section 10-103 of the Act mandates that the Commission make its decision based exclusively upon the record. The Commission finds Staff's proposal unworkable and unreasonable, thus, the record supports a conclusion that the test year level of AMS costs assessed to AIU is reasonable.

In its Brief on Exceptions, Staff also claims that the conclusion in the proposed order is inconsistent with the decision in Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission notes, however, that in the previous AIU rate cases, the basis of Staff's proposed disallowance of AMS costs was not an allocator based upon the relative sizes of AIU and other affiliates. In that case, the Commission identified specific costs that were not adequately substantiated. Here, the record does not support a finding that Staff's proposed allocation factor is reasonable. Of the alternatives available in the record, the Commission finds that the record supports a conclusion that Staff's proposed disallowance must be rejected. This does not mean that in future cases Staff can not propose disallowance of AMS costs if it can develop an appropriate basis.

2. Incentive Compensation Costs

a. AIU's Position

AIU proposes to recover a total of $5,238,000 in incentive compensation expenses in rates. AIU witness Bauer asserts that incentive compensation is a common and necessary component of the total compensation package for employees in the electric and gas utility industry. Over the next decade, according to AIU, the electric and gas utility industry is expecting a substantial number of employee retirements, thus resulting in increased competition for talent. AIU argues that in order to attract and retain qualified employees, and to motivate employees to perform to the best of their ability, AIU must ensure that its total compensation package is competitive. According to AIU, a competent, stable, focused and motivated workforce is critical to providing excellent service to its customers. AIU believes that by using both base and incentive pay, it is able to limit its fixed costs (base pay), yet still reward employee performance (incentive pay).

According to AIU, its incentive compensation plan costs are designed in a manner consistent with market practice. Additionally, AIU argues its incentive plans require achievement of operational performance, thus the plans are designed in a prudent and reasonable manner. AIU claims no party has contested the prudency or reasonableness of the AIU's overall level of total employee compensation. Therefore, AIU believes its proposal to pass the costs along to ratepayers should be accepted. AIU argues that the incentive compensation plan benefits the utility‘s customers and the costs should be recoverable in rates.

According to AIU, it provided evidence of operational and individual goals that can be considered and paid independently of financial goals under the plans. For the 2006 test year, AIU argues key performance indicators were associated with incentive payouts under the plans, such as O&M budget compliance (weighted 20%), capital budget compliance (weighted 20%), safety (weighted 25%), gas O&M (weighted 10%), customer service (weighted 10%); and reliability (weighted 15%). AIU claims each of these metrics benefits AIU`s customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations.

AIU asserts that it presented evidence providing ―financial-based” and ―performance-based” percentage breakdown amounts for the recently modified 2008 incentive compensation plans, which are currently in effect and will be in effect when the Commission approves rates resulting from this case. According to AIU, the 2008 plans focus employees on operational metrics and provide a link between pay and performance.

Ms. Bauer explained that there are some similarities between the 2008 plans and the 2006 plans. AIU says the most significant difference between the 2008 and 2006 incentive plans is that payouts for most of the current plans, with the exception of the Executive Incentive Plan for Officers, are no longer funded only if Ameren meets earnings per share ("EPS") targets. Instead, AIU claims performance on incentive key performance indicators (e.g., operational goals) determines whether or not awards will be available under the plan.

AIU argues that even if the Commission does not consider the modified plans, the incentive compensation plans in effect during 2006 are based on the achievement of operational goals that primarily benefit customers; therefore, incentive compensation expense would be properly recoverable regardless of whether the Commission considers the modified plans. AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance. AIU further argues that it has presented the same type of evidence provided in the Docket No. 03-0403 proceeding, where the Commission approved recovery of incentive compensation expense.

AIU contends that Staff's arguments fail to recognize that a high percentage of the expected payouts under the 2008 plans are not tied to financial performance. AIU also disagrees with Staff's argument that a disallowance is appropriate because AIU‘s incentive compensation plans could be discontinued. According to AIU, incentive compensation is a critical component of AIU‘s total compensation package. AIU says most companies, including AIU, reserve the right to change, modify, add, or eliminate rewards programs as needed.

Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

b. Staff's Position

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that payouts under AIU's incentive compensation plans are dependent upon financial goals of AIU that primarily benefit shareholders. Staff also expressed a concern that ratepayers would provide funding even when no costs were incurred by AIU because the incentive compensation plan goals were not met. Staff contends that the plans are discretionary and may be discontinued at any time. Staff also believes that prior Commission practice supports the disallowance of AIU's incentive compensation costs from operating expenses. Staff notes that the Commission considered the same incentive compensation plans in AIU's last rate case, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Although certain financial thresholds have changed in this case, Staff states that the majority of the arguments provided by AIU are nothing more than a replay of the same arguments offered in its last rate case, which the Commission rejected.

Staff points out that AIU indicates that certain revisions were made to its incentive compensation plans effective January 1, 2008, and provided a schedule showing which of the 2006 costs would have been unrelated to financial targets had the revised plans been in place for that plan year. According to Staff, this presentation is flawed for two reasons. First, Staff argues that nothing has been paid out under the revised plans, which will not be considered until the Spring of 2009; thus, Staff believes the impact of the January 2008 revisions is not yet known and measurable. Second, Staff says AIU did not propose an adjustment that limited incentive compensation expense to the costs unrelated to financial targets.

Staff rejects AIU's argument that since the modified plans are those that will be used to determine incentive compensation expense during the period in which rates established in this case will be in effect, it is appropriate to consider the terms of the modified plans. Staff claims this argument is in direct conflict with AIU's position regarding the Public Utility Fund Base Maintenance Contribution. Staff states that in that instance, AIU argues that since the impact of the change in law will not occur until January 2009, it is not appropriate to consider the change in determining the revenue requirements for these cases. Finally, Staff argues, in prior cases the Commission has made clear that it expects utilities to provide detailed information as evidence of ratepayer benefit resulting from incentive compensation plans. Staff believes AIU has not provided this detailed information nor can the information be provided since AIU‘s revised plans have only been in place since January 2008. As such, Staff contends that the revised plans have not been in existence long enough to provide the type of evidence that must be considered. While AIU asserts that the incentive compensation plans are based on goals such as increased reliability, increased customer satisfaction, increased safety, and improved operational performance, Staff rejects this as detailed evidence the Commission requires. Thus, Staff recommends that the Commission approve its adjustment disallowing incentive compensation costs, a total of $366,000 for AmerenCILCO's gas operations, $567,000 for AmerenCILCO's electric operations, $424,000 for AmerenCIPS' gas operations, $958,000 for AmerenCIPS' electric operations, $468,000 for AmerenIP's gas operations, and $1,135,000 for AmerenIP's electric operations as provided in Schedule 13.07 for each utility.

c. AG's Position

The AG asserts that because AIU's incentive compensation plan results in benefits to shareholders instead of ratepayers, 100% of those program costs should be eliminated from pro forma test year O&M expenses. The AG points out that in more recent cases, the Commission has eliminated incentive compensation plan costs unless the company can demonstrate that the goals employees are expected to achieve would benefit ratepayers, such as the improvement of service quality, reliability, public safety, reducing absenteeism, and cost containment. The AG states that incentive compensation based on financial goals such as maximizing profitability and growth, increasing EPS, or increasing return on equity is beneficial only to shareholders, and not properly recoverable from ratepayers.

According to the AG, in AIU's last electric rate case, the Commission found that AIU's incentive compensation funding measures all relied on EPS targets and disallowed the entire test year compensation from AIU's revenue requirements. In this case, it appears to the AG that all of the test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year operation and maintenance expenses. The AG says the effect of this adjustment is to reduce AmerenCILCO's electric expenses by $521,000, AmerenCIPS' electric expenses by $867,000, AmerenIP's electric expenses by $1,027,000, AmerenCILCO's gas expenses by $365,000, AmerenCIPS' gas expenses by $424,000, and AmerenIP's gas expenses by $468,000 as shown on AG/CUB Ex. 1.1, Schedule DJE-4, page 1.

d. CUB's Position

CUB points out that the Commission has disallowed incentive compensation from utilities' revenue requirements except where the utility has demonstrated that the incentive compensation plan provided a tangible, quantified benefit to ratepayers, by reducing expenses and creating greater efficiencies in operations. Therefore, to include any portion of incentive compensation costs in approved operating expenses, CUB says AIU must demonstrate that the plan confers upon ratepayers' specific dollar savings or other tangible benefits.

In the present cases, CUB argues AIU has not presented any such testimony demonstrating its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma operation and maintenance expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year. CUB contends that because shareholders are the primary beneficiaries of the attainment of AIU's financial goals in terms of increases to earnings and return on equity, it should be those shareholders, not customers, who bear the cost of the incentive compensation related to the achievement of such financial goals.

According to CUB, AIU did not present any evidence that funding measures have changed from the 2004 test year in Docket No. 06-0070/06-0071/06-0072 (Cons.) to the 2006 test year in the present cases. Therefore, CUB argues that it appears that all of the test year incentive compensation expense is still related to the attainment of financial goals. Accordingly, AG/CUB witness Effron proposes to eliminate 100% of the incentive compensation from pro forma test year operation and maintenance expenses.

e. IIEC's Position

IIEC proposes an adjustment to AIU's incentive compensation expense reducing the level of expense included in AIU's cost of service. IIEC asserts that the proposed adjustment should be made to the stakeholder group that benefits from the incentive target, and therefore should pay the related expense. According to IIEC witness Gorman, approximately 50% of the proposed incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets according to Mr. Gorman include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employees safety targets. IIEC asserts that AIU confirmed that its test year incentive compensation programs were identical to the programs for which costs were disallowed in AIU's most recent rate case. It was on this basis that Mr. Effron opined that the result in this case should not differ from the Commission's last decision on the same programs. IIEC says AIU's recent program revisions, made to better reflect past Commission decisions, will affect only post-test year incentive compensation plans and costs.

IIEC asserts that upon consideration of the testimony and arguments of Staff and AG/CUB favoring rejection of all incentive compensation costs, and although IIEC finds them compelling, if the Commission is not persuaded and does not disallow AIU's requested incentive compensation costs in their entirety, IIEC's proposes a ceiling for allowed incentive compensation costs. IIEC believes its proposal is consistent with the record evidence and protects ratepayers from those cost burdens that most clearly do not benefit customers.

f. Commission Conclusion

AIU proposes to recover the costs of its incentive compensation plans in rates. AIU argues its new 2008 incentive compensation plans require operational performance to be achieved before payments are made. According to AIU, its operational and individual goals are based on metrics that can be considered and paid independently of financial goals under the plans. AIU claims each of these metrics benefits AIU‘s customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations. Other portions of AIU‘s incentive compensation plans retain the EPS funding mechanism. Based on the metrics used in either the 2006 or 2008 incentive plan, AIU argues that 100% of AIU's incentive compensation expense should be recovered in rates because the incentive compensation plans are based on metrics that ultimately benefit ratepayers and are part and parcel of a prudent, reasonable, and cost-effective total compensation program.

Staff proposes an adjustment to remove 100% of test year incentive compensation expense from rates. Staff argues that the incentive compensation plans are dependent upon financial goals of Ameren that primarily benefit shareholders. Staff adds that ratepayers would provide funding even if no costs are incurred by AIU because the plan goals are not met. Staff states further that the plans are discretionary, may be discontinued at any time and that prior Commission practice supports the disallowance of incentive compensation. Staff also believes that AIU has not provided the detailed information necessary to conclude that ratepayers benefit from the plans. Nor, Staff continues, can such information be provided since AIU's revised plans have only been in place since January 2008. As a result, Staff contends the revised plans have not been in existence long enough to provide the type of evidence that must be considered.

The AG asserts that AIU's test year incentive compensation expense remains related to the attainment of financial goals. Accordingly, the AG recommends that 100% of the incentive compensation expenses should be eliminated from pro forma test year O&M expenses.

CUB argues that AIU must demonstrate that the plan confers upon ratepayers specific dollars savings or other tangible benefits or the costs can not be reflected in rates. According to CUB, AIU did not present any such testimony demonstrating that its incentive compensation plan confers upon ratepayers' specific dollar savings or other tangible benefits. Accordingly, CUB believes AIU's pro forma O&M expenses should be adjusted to eliminate the incentive compensation expenses incurred in the test year.

IIEC asserts that approximately 50% of the test year incentive compensation program costs are directly attributable to targets that primarily benefit shareholders. Those targets, according to Mr. Gorman, include: O&M budget compliance (20%); capital budget compliance (20%); and gas O&M and standards plan development and implementation (10%). IIEC says the remaining program costs are tied to service reliability and employee safety targets.

The Commission is somewhat encouraged that AIU has begun to modify its incentive compensation plans in a manner that may allow it to recover at least a portion of the costs from ratepayers. The Commission is not opposed to the use of employee incentive compensation plans; however, the Commission maintains that before the costs of such plans will be imposed on ratepayers, a utility must demonstrate that the plans provide meaningful benefits to those ratepayers. Regarding AIU's 2008 incentive compensation plan, with the exception of the Executive Incentive Plan for Officers, AIU claims they are no longer funded only if Ameren meets EPS targets. Unfortunately, the record does not specifically identify the portions of the 2008 plan that are directly dependent upon Ameren meeting financial targets.

The record indicates that AIU has in place incentive compensation plans related to safety (weighted 25%), customer service (weighted 10%), and reliability (weighted 15%) that also do not appear to have payouts that are dependent upon Ameren meeting financial targets. In the Commission's view, it is reasonable to allow AIU to pass the cost of these portions of the incentive compensation plans on to customers. Thus, AIU will be allowed to include in operating expense 50% of the total cost of its incentive compensation expense because the Commission believes that portion provides direct, meaningful benefits to ratepayers and payouts are not dependent upon meeting financial targets that are primarily beneficial to shareholders.

If during the period that the rates approved herein are in effect, however, the incentive compensation plans are revised such that financial goals of Ameren become the payment trigger for a greater portion of the plans, the Commission will not look favorably on incentive compensation expenses in AIU's next rate cases. The Commission is allowing AIU to recover 50% of its incentive compensation expenses with the understanding that at least 50% of the payments made thereunder will based on performance or goals other than Ameren's financial goals.

3. Rate Case Expense

a. Legal Fees

i. AIU's Position

According to AIU, the requested amounts for legal expenses in this case are reasonable. AIU estimates legal expenses for this proceeding as $1,162,000, of which $605,000 was estimated to be incurred by the time hearings began. Through April 30, 2008, AIU asserts that it received invoices for approximately $670,000 for legal expenses. Although rate case expenses were running above budget, AIU states that it is not proposing any upward adjustment to the requested level of rate case expense. AIU argues that the estimated and actual rate case expenses in this case are proving to be reasonable in comparison with actual and estimated costs in the previous rate case.

AIU claims that Staff's assertion that it received invoices —two days prior to the evidentiary hearings," without enough time for Staff witness Ebrey to analyze the invoices contradicts Staff's own statements and testimony. AIU submits that Staff offered no record cites in support of this claim. To the contrary, AIU claims Ms. Ebrey testified at the evidentiary hearing that she had, in fact, reviewed the invoices, again, mentioning her —concerns about a number of the items that appear on the invoices." (Tr. at 791-92) AIU says Ms. Ebrey did not testify, however, that she did not have enough time to review the invoices.

ii. Staff's Position

Staff proposes to limit the cost of legal fees to the amount actually supported by invoices, as AIU did not provide sufficient support for its requested level of legal fees and Staff could not determine the reasonableness of the estimate for those costs. According to Staff, the record in this case only reflects $470,000 in questionable legal fees for rate case expense. Staff characterizes these costs as questionable since it did not receive sufficient detail to be able to analyze the costs until two days prior to the start of the evidentiary hearings. Since no investigation of the costs in question was possible, Staff recommends that the Commission should not allow those costs to be recovered as rate case expense. In Staff's view, the Commission should only allow the costs for attorney's fees that AIU properly supported.

iii. Commission Conclusion

As the Commission understands it, AIU proposes to reflect in rates approximately $194,000 in legal expenses from the law firm of Jones Day Reavis & Pogue for each utility's electric operations and each utility's gas operations. The Commission also understands that, in contrast, Staff proposes allowing $44,000 for each utility for these costs. Staff proposes disallowing all prospective legal expenses for which invoices were not provided. Additionally, Staff suggests that some invoices provided by AIU were provided so late in the process that Staff was unable to adequately review them. Thus, Staff's proposed disallowance effectively disallows a portion of actual costs incurred for which invoices were provided.

The Commission is troubled by the Staff proposal. The proposal to allow recovery of only legal costs associated with those invoices that Staff has adequately reviewed puts AIU in a situation where it must incur costs but can not recover those costs from ratepayers. There is no question that to effectively pursue this rate increase request, AIU will continue to incur legal expenses after Staff files rebuttal testimony and even after the evidentiary hearings. Obviously, AIU can not produce invoices for Staff to review before the legal work is done. The proposal to disallow 100% of costs for which invoices for rate case legal work that were not adequately reviewed by Staff is fundamentally unfair. A more fair approach might be to propose disallowing the percentage of forecasted costs based upon the percentage of actual legal expenses that were found to be improperly incurred or billed. Other reasonable approaches might be to determine that legal expenses were overestimated by some amount or percentage, or that the legal expenses themselves were unreasonably high. Staff's proposal, however, would inevitably lead to costs that must be incurred but could not be recovered. This is particularly true when combined with Staff's position in this proceeding with respect to unamortized rate case expense, whereby only amounts previously approved by the Commission are eligible for recovery on a prospective basis. Staff's approach would be an unfair and unreasonable result. Based upon the record in this proceeding, the Commission hereby rejects Staff's proposal to disallow legal costs associated with these rate cases.

b. Gannett Flemming Costs

i. AIU's Position

Gannett Flemming, a consulting firm hired by AIU, prepared a depreciation study for AIU in this proceeding. AIU states that Staff witness Ebrey accepts its rebuttal position for the costs of the depreciation study; however, AIU claims she fails to take into account invoice updates provided for March and April that include an additional $25,000 in post filing support. It is AIU's position that Ms. Ebrey only accounted for $20,000 of actual post filing support, for only two months of work – January and

February 2008. According to AIU, it incurred $45,000 of actual post filing support through April compared to Staff's $42,000 proposal meant to cover the entire post filing cost. AIU contends that considering the electric depreciation study remains contested and that total post filing support costs through April are 41% of the total proposal ($45,000 / $111,000 = 41%), AIU requests post filing support in the amount of $25,000 per electric utility and $12,000 per gas utility, and complains that Ms. Ebrey only proposes allowing $10,000 per utility for post filing support.

ii. Staff's Position

Staff accepts AIU's levels of reduced costs for the depreciation studies; however, Staff says it is unable to accept AIU's cost projection for costs associated with post-filing support proposed by AIU for either the gas or electric utilities. Staff maintains that AIU has not shown the actual costs estimates from Gannett Fleming. AIU, according to Staff, provided only the total amounts included as rate case expense and did not provide any tracking of actual costs. Staff says that based on invoices received from AIU, an average of $3,400 per utility (a total of just over $20,000) has been expended for post-filing support of the depreciation studies. Staff's proposal allows an additional $7,000 per utility, or a total of $42,000, for post-filing support for the depreciation studies. Given the level of post-filing support reviewed by Staff at the time of rebuttal testimony, Staff's contends its proposal is reasonable. In its reply brief, Staff explains that it proposes allowing an additional $17,000 to cover costs for May through the end of the hearings that is in addition to the $45,000 in costs incurred from November through April that Staff says is supported by invoices.

iii. Commission Conclusion

Although it is not entirely clear, it appears that AIU is proposing to recover $39,000 from each utility's gas customers and $35,000 from each utility's electric customers while Staff is proposing AIU be allowed to recover $37,000 from each utility's gas customers and $20,000 from each utility's electric customers. Again, while not entirely clear, it appears that the reasons that AIU and Staff disagree about the level of Gannett Fleming costs that should be passed on to ratepayers relates to invoices for March and April, 2008 as well as the level of estimated costs that had not been incurred at the time Staff took its final position. Consistent with its conclusion immediately above regarding legal expenses, the Commission rejects Staff's proposal to exclude from operating expenses costs attributable to Gannett Fleming that have not yet been incurred. Of the proposals in the record, AIU's estimate of the costs is the most reasonable and is hereby adopted.

c. Energy Efficiency Witness

i. AIU's Position

AIU understands that Staff recommends disallowing the entire cost of AIU's energy efficiency expert witness in this case, Mr. Hanser, based on Staff's belief that the expert witness was hired to provide testimony that does not relate to this rate case. AIU argues that energy efficiency and Mr. Hanser's testimony do directly involve AIU's rate cases and the setting of rates. According to AIU, Mr. Hanser's testimony was an essential component of explaining the Rider VBA proposal. He also testified regarding the programs implemented by other utilities in the Midwest, expenditures directed to such programs, and appropriate spending levels. According to AIU, energy efficiency initiatives directly affect cost recovery, and AIU would only pursue such programs contingent upon approval of Rider VBA. Lastly, AIU argues, without this direct testimony filing, its rate case presentation would have been deficient. Thus, AIU contends the energy efficiency rate case testimony costs are prudently incurred, and should be allowed.

ii. Staff's Position

Staff recommends disallowing all costs proposed by AIU for its energy efficiency witness since, according to Staff, Mr. Hanser's testimony does not relate to the setting of base rates, the subject of the rate cases, but rather discusses energy efficiency programs, their merits, and associated costs. Staff notes that these topics are directly related to the current Docket No. 08-0104, in which AIU petitioned the Commission for approval of the natural gas energy efficiency plan and the associated Rider GER.

iii. Commission Conclusion

The Commission understands that AIU has the burden to prove its case in any rate proceeding, and in order to efficiently accomplish such a task must make judgment calls of what type of witnesses will be needed to present its case to making a proper showing supporting its proposals. The Commission believes it is unlikely that AIU retained services from an expert that AIU believed was not needed. The Commission takes into consideration various factors that come into play in any case, such as preparing a witness, preparing direct examination and reviewing the expert analysis and reports, and meeting with the expert throughout the case. It does not seem logical to the Commission that AIU would retain an expert that it believed it did not need in support of its case. Whether the Commission approves Rider VBA is not relevant, as AIU has the right, and arguably the obligation, to support any proposal it makes in a rate case. AIU's argument that Mr. Hanser was retained in support of Rider VBA is logical. Therefore, the Commission believes the costs for the energy efficiency witness should be allowed and Staff's proposal to remove the costs from operating expenses is hereby denied.

d. Unamortized Rate Case Expense / Amortization Period

i. AIU's Position

AIU asserts that the AG/CUB's recommendation to disallow unamortized rate case expense is essentially asking the Commission to reverse its prior order approving the amortization of costs incurred in association with Docket Nos. 06-0070/06-0071/06-

0072 (Cons.). AIU argues this is inappropriate because such an adjustment would deny AIU the opportunity to recover its Commission approved, prudently incurred costs.

AIU asserts that because it expects to be filing rate cases on a 2-year schedule in the foreseeable future, it proposes to amortize this rate case expense over a two-year period. AIU notes that Staff proposes a 5-year amortization period for gas rate case expense and a 3-year amortization period for electric rate case expense. According to AIU, Staff's proposed amortization periods are too long, and unreasonable in order for AIU to recover gas and electric rate case expense. AIU submits that it has never been on a 5-year rate case filing schedule and AIU argues that facts and issues have changed for both gas and electric delivery systems since the last rate cases were filed. AIU suggests that costs and other rate inputs have become increasingly volatile. AIU further argues that there are several factors influencing AIU's authorized return as well as system improvements that will continue into the future. AIU asserts it is committed to increasing improvements to the electric distribution system infrastructure. These issues, according to AIU, will fuel the need to file rate cases on a more frequent basis. Thus, AIU believes its proposed 2-year amortization period for both gas and electric rate case expenses is reasonable under current and expected circumstances and should be approved.

ii. Staff's Position

Staff recommends an adjustment for rate case expense of $259,000 in operating expenses for each gas utility and $215,000 in operating expenses for each electric utility reflecting the inclusion of unamortized rate case expense from prior rate cases. These proposed adjustments reflect Staff's recommended amortization periods of 3 years for the electric utilities and 5 years for the gas utilities. Staff claims these periods are based on time periods between prior rate case filings.

Staff suggests that its proposed amortization periods are consistent with the time periods between the effective dates of the most recent rate changes of AIU. According to Staff, AIU's proposal to recover rate case expense over a 2 year amortization period for both the gas and electric utilities is a rather aggressive amortization period since it will have been 5 years since the current AmerenCILCO and AmerenCIPS gas rates have been in effect and 3 years since the current AmerenIP gas rates have been in effect when the rates in the instant proceedings become effective. According to Staff, while the 2 year period is representative for the time since the last electric rates were set, a 2 year period is shorter than any rate case amortization approved by the Commission in recent history. Staff argues that there is a risk involved with setting a shorter amortization period versus having a longer amortization period, noting that if the amortization period is less than the period rates are in effect, AIU would recover more than the Commission-approved rate case expense. Staff opined that the ratepayers would then bear the risk with no risk to the shareholders of under recovery.

Staff argues that its recommendation is consistent with AIU's pro forma adjustments for rate case expense in these proceedings, which include a component for unamortized rate case expense. Staff points out that AIU offered no rebuttal to Staff witness Ebrey‘s discussion regarding the risks involved with a shorter amortization period for rate case expense.

iii. The AG and CUB's Position

The AG and CUB argue that AIU's proposed amortization of prior rate case expenses should be rejected because it allows AIU to over-recover its rate case expenses. According to them, the purpose of including the normalized rate case expense in the cost of service is not to guarantee a dollar-for-dollar recovery of the rate case expense incurred, but rather to allow a reasonable opportunity to recover the cost of the rate case by including what is deemed to be a ―normal” rate case expense in the cost of service. The AG and CUB assert that the problem occurs when the actual period between rate cases is different than that assumed in calculating the amortization of rate case expenses. Thus, they recommend eliminating the amortization of the prior rate case costs from the revenue requirement in these cases, which will then reduce AmerenCILCO electric expenses by $570,000, AmerenCIPS electric expenses by $570,000, AmerenIP electric expenses by $570,000, AmerenCILCO gas expenses by $170,000, AmerenCIPS gas expenses by $101,000, and AmerenIP gas expenses by $303,000.

iv. Commission Conclusion

The Commission rejects AIU's proposed two-year amortization period for rate case expenses. From a historical perspective, this is simply too short of a period. While it is true that in the recent past AIU's gas electric rate cases have been relatively frequent, there have been periods lasting almost a decade or more in which the utilities did not request a rate case. The Commission is not certain when the trend of relative frequent rate cases will change, but it fully expects it to happen. Contrary to AIU's suggestions, the regulatory environment is not so changed that it warrants a two-year rate case amortization period. The Commission agrees with Staff that there is a risk to the ratepayers of overpayment if AIU‘s proposal were adopted. The Commission therefore adopts Staff‘s proposal to utilize a five-year amortization period for gas rate case expenses and a three-year amortization period for electric rate case expenses.

As for the AG and CUB's proposal to totally exclude from rates the unamortized rate case expenses approved in AIU's last rate, the Commission rejects this proposal. Contrary to their argument, the Commission does not establish a "normal" level of rate case expenses as it does for other types of cost that are prone to variation over time. Instead, the Commission typically allows a utility to capitalize those costs and amortize them over some reasonable period of time. The AG and CUB proposal would deny AIU the opportunity to recover reasonable, prudently incurred costs. To the extent AIU was authorized to recover rate case expenses in its last rate case and there remain unamortized balances of such authorized costs, AIU will be allowed to reflect such costs in rates in this proceeding.

e. Navigant, Concentric Costs

i. AIU's Position

AIU points out that Staff raises several arguments regarding AIU's rate case expense costs relating to Navigant and Concentric. According to AIU, while Staff accepted all expenses invoiced by Navigant, Staff questions the level of the Navigant and Concentric costs leading up to AIU's rate case filing and, according to AIU, generally disregards the supporting facts that costs associated with the Navigant invoices were actually incurred, prudent, and reasonable.

Staff witness Ebrey claims that certain costs associated with Concentric would not have been incurred if AIU had not switched consulting firms from Navigant to Concentric. AIU argues it did not incur additional costs by continuing to work with their expert witness, Mr. Adams, after he left Navigant and began work for Concentric on July 1, 2007. AIU claims that estimated costs of post-filing services increased in October 2007, several months after Mr. Adams switched to Concentric. At that time, AIU explains it reexamined the scope of work requested from Mr. Adams, and determined that AIU would need significantly more post-filing assistance from Mr. Adams than previously anticipated.

AIU asserts that Staff's hypothesis fails to take into account that if the AIU had continued to use Navigant after Mr. Adams had switched firms, they would have been forced to switch their chosen expert witness, who was retained for his experience, knowledge, and familiarity with AIU's operations and business.

AIU also points out that Staff raised concerns regarding a paid Navigant invoice marked —Do Not Bill." According to AIU, Staff disregards its explanation that the notation —IS Do Not Bill To" was an error on the part of Navigant. AIU argues that it should not be penalized for a mistake on a vendor's invoice. In support of this proposition, AIU argues that as Manager of Regulatory Accounting, Mr. Weiss explained that he reviewed the invoice and determined that the total hours billed and the summary hours listed by the consultant was reasonable.

AIU contends that it provided Staff with the Concentric invoices supporting the lead lag study totaling $100,000, compared with the original budgeted amount of $130,000. Thus, actual costs are in line with estimates. AIU also contends that it provided invoices supporting the AMS market study totaling $653,000 compared to the original budgeted amount of $750,000. AIU accepts the lower amount and applies it to the updated rate case expense.

AIU asserts that while Staff concedes the increased level of complexity associated with rate filings, Staff does not fully appreciate that with increased complexity comes increased costs. AIU witness Wichmann testifies that the discovery process in these rate cases has been far more exhaustive than in the last delivery service rate cases. He states that the post-filing support estimate was increased with the expectation that Concentric would need to budget for a significant increase in time and expense due to the higher level of complexity in the rate filing and testimony provided with the filing, which AIU says was borne out through substantial additional support for unanticipated issues, including the proposed plant addition disallowances.

ii. Staff's Position

Staff recommends reducing the amount of costs for the Navigant/Concentric consultants by a total of $270,000 (from $429,000 to $385,000 for each gas utility and $401,000 to $355,000 for each electric utility). According to Staff, a review of the support provided for Navigant/Concentric costs raises a number of concerns. Staff argues there is a potential conflict of interest for the review and approval of certain charges for payment. Specifically, the conflict of interest issue concerns charges by the consultant who is the son of the Manager of Regulatory Accounting at AMS, the individual to whom the invoices from Concentric and from Navigant are addressed. According to Staff, in most cases, the Manager of Regulatory Accounting signs off that the bills are "OK" to pay. Staff submits that the conflict of interest allowed costs that should not have been paid by AIU as rate case expense for recovery from ratepayers. These costs include entertainment costs, sick pay, incorrect hotel charges, and other travel expenses. There were also billing errors that were not adequately explained, and transition period costs from Navigant paid by AIU. Staff also noted inconsistent and increased billing rates during the duration of the consultation; and budgeted costs for specific projects above amounts expended. Based on these concerns, Staff recommends that the amount of rate case expense associated with Navigant/Concentric consultation be set at $385,000 for each gas utility and $355,000 for each electric utility.

Staff recommends that the Commission order AIU to perform an internal study of all instances in which an individual who is responsible for the approval of charges for payment has conflicts of interest with the individuals performing the work or receiving payment for the work. Staff says the Commission should further order AIU to institute safeguards to minimize the future occurrence of instances that raise this conflict of interest, and to report to the Commission the safeguards that are implemented with a copy to the Manager of Accounting within six months of the date of the order in this proceeding.

iii. Commission Conclusion

With regard to the alleged transition costs attributable to Navigant/Concentric, there is no dispute that Mr. Adams changed firms. At that time, AIU believed that it needed to continue its relationship with Mr. Adams to support its rate cases, which the Commission believes to be a reasonable conclusion. Having said that, however, it seems logical that AIU would have to incur additional costs to retain two consulting firms for a period rather than one, as well as to coordinate and administer the activities of two consulting firms rather than one.

With regard to the alleged conflict of interest, AIU attempts to dismiss the possibility by alleging that the AIU employee at issue was not actually approving the costs in question but that it was AIU's attorneys approving the costs. Given the circumstances, AIU's explanation is not convincing. The Commission, however, does not see a need to require AIU to perform an extensive analysis of potential conflicts of interest and report back to the Commission. The Commission simply directs AIU to ensure that such potential conflicts do not occur again and to avoid the appearance of impropriety. If such a situation arises again, any associated expenses will not be viewed favorably to AIU.

AIU claims that it should not be penalized when a vendor incorrectly bills it; however, Staff has raised legitimate concerns about billing errors that the Commission is unable to fully resolve. As a result of the legitimate concerns raised regarding Navigant/Concentric billing issues, the Commission finds Staff's proposed disallowances to be reasonable and they are herby adopted.

4. Uncollectibles Expense

a. AIU's Position

AIU proposes that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. According to AIU, the data shows an upward trend in net write-offs since 2003. For each of the electric utilities, AIU indicates that net write-offs are highest in 2007. For two of the three electric utilities net write-offs are lowest in 2003. For two of the three gas utilities, the highest net write-offs are in 2006 and the lowest in 2003. AIU submits that this upward trend demonstrates that the most weight should be placed on the most recent data.

b. Staff's Position

Staff proposes a 5-year average of net write-offs as a percentage of revenues consistent with the time period used in the most recent prior AIU rate cases, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). Staff disputes the claim by AIU that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Staff argues that AIU offers neither any explanation for the increased level of net write-offs experienced in 2007, nor any evidence that the same level of net write-offs will continue into the future. Staff states that the data presented by AIU does indicate, however, that the level of net write-offs fluctuates over time, necessitating the normalization approach.

Staff's proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs also removes the impact of Section 16-111.5A(f) of the Act in the 2007 revenues booked by

AIU. AIU witness Stafford claims that Staff_s adjustments to 2007 revenues are inappropriate since Staff did not establish that the 2007 adjustments are unique or provide any supporting analysis to demonstrate that no other adjustments should be made for other variances.

Staff recommends the Commission approve its proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs, including the adjustment removing the impact of Section 16-111.5A(f) of the Act, on the 2007 revenues booked by the utilities.

c. CUB's Position

CUB recommends that pro forma test year uncollectible accounts expense be normalized based on the average of net-write-offs to revenues for the 3 years 2005-2007. CUB's recommendation was adopted by AIU.

d. CNE-Gas' Position

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. However, CNE-Gas believes the Commission must direct AIU to eliminate commodity-related uncollectible recovery from transportation customers. In support of its recommendation, CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to AIU, which does not supply gas to transportation customers. CNE-Gas argues that given recent Commission precedent and the inequity of AIU's charging transportation customers for purchased gas costs, the Commission must require AIU to remove the recovery of uncollectible commodity-related costs from its transportation rate schedules.

e. AG's Position

The AG argues that in order to ensure that the pro forma adjustment accurately reflects actual experience, the pro forma test year uncollectible accounts expense should be normalized based on the average of net-write-offs to revenues for the three years 2005–2007. The AG indicates that AIU ultimately agreed with it on this proposal, making a minor modification that the AG does not dispute.

The AG also argues that the gross revenue conversion factor should be modified so that the revenues used in the denominator are consistent with expenses used in the numerator. According to the AG, AIU includes the effect of uncollectible accounts in its calculations of the Gross Revenue Conversion Factors used to convert the calculated income deficiencies into the required additional revenues, in effect recognizing the additional uncollectible accounts related to the proposed rate changes. In calculating the uncollectible accounts rates to be used in the gas Gross Revenue Conversion

Factors, according to the AG, AIU took the ratio of total uncollectible accounts to gas delivery service revenues excluding purchased gas revenues. The AG argues that this results in a mismatch which overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The AG submits that the uncollectible accounts rates included in the Gross Revenue Conversion Factors should be modified so that the revenues used in the denominator are consistent with the expenses used in the numerator. The appropriate gas Gross Revenue Conversion Factors, according to the AG, are 1.146%, 1.226%, and 0.937% for AmerenCILCO, AmerenCIPS and AmerenIP, respectively, as compared to AIU's proposed uncollectible accounts rates of 5.766%, 4.582%, and 6.116%, respectively.

f. Commission Conclusion

AIU, CUB, and the AG propose that the Commission determine the uncollectible percentage for each utility using a 3-year average of 2005-2007 net write-offs divided by revenues. AIU argues that the Commission should exclude historical data from 2003 because the use of that data would understate the uncollectible percentage and unfairly distort the uncollectible expense levels. Staff proposes a 5-year average of net write-offs as a percentage of revenues. Staff disputes AIU's claim that its proposed 3-year average for net write-offs is more representative than the 5-year average proposed by Staff. Thus, Staff recommends a proposed adjustment to uncollectibles expense and the uncollectibles rates to be used for each utility based on the 2003 through 2007 net write-offs.

It appears to the Commission that historical data from 2003 understates the uncollectible percentage and unfairly distorts the expense. It also appears that, generally speaking, there is an upward trend in AIU's uncollectibles. Therefore, the Commission finds that the proposal to use a three-year average of 2005-2007 net write-offs divided by revenues is reasonable and should be adopted.

The AG argues that AIU overstates the uncollectible expense rates to be included in the gas Gross Revenue Conversion Factors applicable to gas delivery service. The Commission finds that the AG's argument in regards to the Gross Revenue Conversion Factor issue is misplaced. The Commission has considered the level of uncollectibles authorized in this Order when establishing the appropriate Gross Revenue Conversion Factor used to calculate AIU's revenue requirements in this proceeding.

CNE-Gas recommends that the Commission require AIU to exclude transportation customers from the recovery of uncollectible commodity costs. CNE-Gas argues that AIU recovers natural gas commodity-related uncollectible expense through the gas delivery service rates of both system and transportation customers. CNE-Gas argues it is unfair for transportation customers to pay for uncollectible commodity costs to both AIU, which does not supply gas to transportation customers, and the transportation customers' suppliers. It appears that no party objects to CNE-Gas' proposal. The Commission finds CNE-Gas' proposal to exclude system and transportation customers from the recovery of uncollectible commodity costs to be fair and reasonable, it is therefore adopted.

5. Injuries and Damages Expense - AmerenIP

a. AIU's Position

AIU agrees with Staff witness Ebrey's proposal to normalize injuries and damages expenses over a 5-year period for AmerenIP, but has rejected what it describes as her subjective “hybrid” normalization approach. AIU argues that its normalization calculation appropriately includes all of the AmerenIP electric 2005 actual payments in the injuries and damages expense calculation. AIU contends that the result of this calculation is fair and consistent with the methodology previously approved by the Commission, and results in a true “normal” expense level as reflected in Ameren Ex. 20.7.

AIU argues that while Ms. Ebrey purports to use the same methodology to normalize injuries and damages expense that was approved by the Commission in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), she in fact does not. In that case, AIU claims the Commission approved a 5-year average of AIU's injuries and damages expenses. According to AIU, Ms. Ebrey appears to combine this normalization methodology with the one approved by the Commission in Docket Nos. 07-0241/07-0242 (Cons.), where the Commission approved the utilities' actual test-year expenses, adjusted for a highly unusual credit recorded in a prior year. Thus, Staff combines these two different methodologies to produce what AIU believes is an unfair result, by both normalizing and removing costs.

According to AIU, Staff's approach is not reasonable because the point of normalizing is to flatten out the peaks and valleys of a volatile cost component, by averaging actual costs over a reasonable time period. In this case, AIU argues that Staff has subjectively chosen to remove certain costs from this average, which does not result in an accurate “normal” calculation. AIU's proposed cost level averages actual costs over a 5-year period, which according to AIU is a reasonable period of time over which to account for the highs and the lows. AIU also notes that Ms. Ebrey does not claim that AIU's proposed injuries and damages expense level is unreasonable or does not reflect a “normal” amount.

According to AIU, Ms. Ebrey claims that the issue hinges on whether the costs she chose to remove from the 2005 payouts are “extreme and unusual.” AIU argues that this argument misses the point because AIU considers all injuries and damages to be unusual. There is no “normal and expected” accident which, according to AIU, is why injuries and damages are a volatile cost component. AIU maintains that normalizing flattens out the highs and lows of “extreme and unusual” costs, by averaging actual costs over a reasonable time period.

b. Staff's Position

Staff proposes an adjustment to injuries and damages expense for AmerenIP's electric operations that removes consideration of the extraordinary claims included in the 2005 payouts from the calculation of a normalized amount. Staff claims AIU offered no evidence refuting Staff's position that the claims removed from the 2005 payout level were extreme and unusual. Staff states that AIU witness Wichmann was unable to confirm whether or not the type of, as well as the dollar magnitude of, the claims excluded by Staff were likely to occur annually. Thus, according to Staff, the 2005 claims that are outside the routine level and type of injuries and damages expense are appropriately excluded for the calculation to normalize AmerenIP's electric utility injuries and damages expense. Staff recommends that the Commission adopt Staff's adjustment of $2,654.000 to AmerenIP injuries and damages expense of electric operations.

c. Commission Conclusion

While AIU correctly suggests that it is reasonable to expect injuries and damages expenses to fluctuate from year to year, given the nature and magnitude of the 2005 AmerenIP injuries and damages expenses, this does not appear to be a routine variation. The Commission finds that the injuries and damages expense that occurred at AmerenIP during 2005 is unusually high and should be considered an outlier. The Commission, however, does not agree with Staff's approach to dealing with this unusual situation. By adjusting the 2005 figure and including it in the 5-year average, the Commission observes that Staff changed the 2005 value from the highest of the 5 into the lowest. The Commission believes the superior approach in this situation is to remove entirely the 2005 injuries and damages from the calculation. Based on this conclusion and using the information on Staff Ex. 1.0, Schedule 1.11 IP-E, the Commission effectively finds that the injuries and damages expense for AmerenIP should be based upon the average of 2003, 2004, 2006, and 2007.

6. Energy Toolkit

a. AIU's Position

AIU has proposed recovering the cost of its Energy Toolkit in the operating expense level for each of its utilities. AIU claims that the Energy Toolkit is a unique program that stands on its own merits and would be of value to customers, however, if the Commission does not approve recovery of the costs for this available program as Staff suggests, AIU will have no alternative but to discontinue the program.

While AIU agrees with Staff that there are other sources of information that may assist customers in better understanding and managing their energy costs, AIU avers that there is no other available site that has the capability of automatically loading, storing and analyzing individual customer usage. AIU opines that there is no other site that allows the customer to complete an individualized energy analysis audit based on

AIU's metered usage, area weather, billing cycle data, changes to owned appliances, and individual lifestyle, and then integrates these pieces of customer-specific information in a format that allows a typical AIU residential customer to better understand and manage their energy expenses.

AIU notes that while Staff witness Ebrey researched similar energy efficiency programs on the internet, she did not identify any site that contained the same information as found in the Energy Toolkit. Ms. Ebrey claims she reviewed a number of sites that had information of the type found in the Energy Toolkit. AIU opines that Staff appears to view the Energy Toolkit as being synonymous with any internet site or program related to energy efficiency. AIU submits that Staff's misunderstanding could be due to the fact that many energy efficiency programs have the same goal or objective and provide information and education to customers in an effort to meet this goal. AIU argues that the Energy Toolkit is a unique service that complements the approved programs and is not duplicative of other internet sites.

AIU claims that the Energy Toolkit would even provide benefits to customers that do not have access to the internet. AIU witness Martin states the Energy Toolkit contains functionality that would act as an enhancement to AIU's customer information system. He says this functionality allows call center agents to provide much of the same information and analysis to residential customers contacting AIU via phone just as if the customer accessed the toolkit on the web. The call center agent interface to the Energy Toolkit, AIU claims, allows the agent to assist with an energy audit, explain monthly, seasonal or annual changes to price and usage experienced by a customer. The Energy Toolkit, AIU contends, will also allow the agent to generate and mail a customized report to the caller, and would allow customers that contact AIU by phone to receive much of the same energy analysis information.

AIU asserts that the Energy Toolkit not only provides education and information about energy efficiency, but may also be used by AIU customers or call center agents to understand many aspects of their utility bill including effects of price, metered usage, weather, and billing cycle. The Energy Toolkit, AIU argues, is a single site that will be deployed specifically for AIU gas and electric customers that gathers data and information from a variety of sources, synthesizes the data into a meaningful format, and presents this customer-specific data in a manner that simplifies the process of understanding, comparing, and managing their energy expenses. AIU says the Energy Toolkit costs will not be recovered through Rider EDR.

AIU believes that the Energy Toolkit provides value to its customers by providing customers an informational and educational resource and that enables them to make informed decisions regarding their energy usage. For a customer to try to similarly self-educate, AIU argues, would be extremely difficult, and would require a significant amount of research, time, effort, and analysis. AIU claims the information the Toolkit provides has the potential to save customers significant amounts off of their energy bills over time, depending on the customer and on individual choices. In summary, AIU believes the Energy Toolkit program provides meaningful ratepayer benefits, thereby justifying recovery of the costs of this program in rates.

b. Staff's Position

Staff recommends an adjustment to disallow costs for the Energy Toolkit because, according to Staff, the new program does not provide any additional benefit or information to AIU's customers that is not already available through other sources, and it is not necessary for the provision of safe and reliable utility service. Staff argues that the program is not as unique as AIU claims. Ms. Ebrey, after referring to a number of similar web sites, indicates she found many sites that required similar AIU customer specific information to be input that would also generate customer specific billing information on energy usage.

Staff maintains that no measurable added value to customers has been identified by AIU. Staff disagrees with AIU's claim that there is value inherent in making the tool available to its customers as an informational and educational resource that might allow customers to make informed decisions regarding their energy usage. Staff opines that this informational and educational resource is simply a different delivery mechanism for information and education that is already planned under the Energy Efficiency Demand Response Plan. Staff argues that it is unreasonable for ratepayers to bear the cost for this duplication of information. Staff thus recommends a $275,233 adjustment disallowing AIU's pro forma adjustments for the Energy Toolkit.

c. Commission Conclusion

The Commission believes that AIU's Energy Toolkit can assist ratepayers in making decisions and taking actions to improve energy efficiency, reduce energy usage, and ultimately lower their utility bills. While some of the information provided through the Energy Toolkit is available through other resources, the Energy Toolkit is very detailed and personalized for each individual customer. Taking into consideration the relatively modest cost of the program, the Commission finds that the Energy Toolkit program provides customers an excellent opportunity to reduce their energy usage and that therefore the associated costs should be reflected in AIU's rates. In order to ensure that customers are aware of the Energy Toolkit, the Commission directs AIU to periodically include information about the availability of the Energy Toolkit in its bill inserts (if it is not already doing so).

7. Collateral and Prepayments

a. AIU's Position

AIU believes it should be allowed to recover the costs associated with prepayment and collateral posting for gas purchases. AIU claims such additional costs are necessary and will remain necessary unless and until AIU carries investment-grade ratings. AIU says that for gas operations, a cost of providing service is the requirement that utilities either prepay for certain services or post collateral. Such a requirement, AIU asserts, is due to limited access to unsecured credit, primarily driven by AIU's below-investment grade credit ratings.

AIU insists that cash collateral and prepayments increase the costs of providing gas. For cash collateral postings, AIU says the cost is estimated by finding the monthly negative carry and multiplying by the monthly amount of the collateral postings. AIU states that the negative carry is estimated as the difference between the actual short-term borrowing rates in effect for AIU each month and the actual Federal Funds Target Rate in effect each month. The Federal Funds Target Rate is the rate of interest often received for cash balances posted to counterparties. For prepayments, AIU says it does not receive interest, as prepayments are considered early payment for pending deliveries rather than as cash deposits that are being held over time. Therefore, AIU says the cost of prepaying is estimated by multiplying the actual short-term borrowing rates in effect each month for AIU by the monthly amount of prepayments.

According to AIU, prepayment requirements and collateral postings to assure performance most often arise under North American Energy Standards Board (“NAESB”) agreements or International Swap Dealers Association (“ISDA”) agreements with various counterparties. Because AIU's ratings are below investment grade, it says many of its respective NAESB and ISDA counterparties have availed themselves of a contractual right to require the posting of performance assurances. In AIU's view, it is reasonable to expect that many counterparties to these agreements will likely continue to seek to be fully secured with respect to any positive exposure it has until AIU's ratings return to investment grade levels. AIU says if it were to fail to provide prepayment as contractually required, it could be cited for default and could be at risk in its efforts to secure and maintain stable, long-term gas supplies for its ratepayers.

Depending on the circumstances, upon receipt of a request for prepayment, AIU claims it could need to provide prepayment on the same day or on the next business day. Within many of the agreements to which AIU is principal, it says calculations of credit exposure take place daily. In instances where a counterparty calculates exposure to AIU that exceeds any unsecured credit to which AIU is entitled, AIU claims the counterparty would have a contractual right to require a margin posting. Such calculations and margin calls can, and often do, take place each business day. In most cases under ISDA contracts, AIU says counterparties have one business day to post the margin as requested. As is a standard practice within the energy industry, AIU says it performs the same calculations as its counterparties: (1) in order to determine the appropriateness of any margin call received by AIU; (2) to determine whether margin posted by AIU should be returned; and (3) to determine whether AIU should request margin from any of its respective counterparties.

AIU claims that the amounts of cash collateral and prepayment can change monthly or more frequently and are susceptible to change as often as daily. AIU says prepayment amounts may change monthly or more frequently, depending upon the nature of the agreement and whether the transaction is base load or swing. Under a monthly base load contract, AIU states that the prepayment amounts can vary due to varying estimated monthly volumes and varying prices applicable to the volumes. Under swing packages, AIU says it may exercise a right to call on variable amounts of gas depending upon the need that exists at that time, and prepayment would vary according to gas volumes and pricing. With respect to cash collateral, AIU indicates the amounts may change daily, depending on the nature of each agreement and the transactions executed under each agreement.

AIU claims that if it carried investment grade ratings, in most instances it would be able to pay for gas supplies during the month following the receipt of gas deliveries, which would substantially reduce and possibly eliminate prepayment-related costs currently borne by AIU. AG/CUB witness Effron reviewed the collateral and prepayment costs as estimated by AIU in response to AG Data Request 4.13. He proposes modifications to the prepayment cost amounts estimated by AIU, indicating: (1) AIU excludes the prepayment balances in the first available month in which data was available; and (2) he recommends the latest known applicable interest rate be used rather than the month-by-month interest rates. In addition, Mr. Effron‘s Schedule DJE-4, page 4, indicates he is averaging the individual monthly amounts of prepayment postings to obtain an average monthly prepayment posting to which he then applies the most current annual rate of interest. In surrebuttal, AIU witness Moloney concludes that the methodology used by Mr. Effron to calculate his proposed —Annual Interest" amounts (AG/CUB Ex. 4.1, Schedule DJE-4, page 4) is acceptable. The —Annual Interest" reflected in AG/CUB Ex. 4.1, Schedule DJE-4, page 4 is as follows: AmerenCILCO ($353,000); AmerenCIPS ($76,000); AmerenIP ($672,000).

Staff witness Ebrey recommends a disallowance of AIU's pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments. She bases the adjustment on her claim that AIU has not shown that these collateral postings and prepayments are solely for purchased gas. Ms. Ebrey also claims that, if the collateral posting and prepayments are solely for purchased gas costs, they would be considered for recovery through the rates determined under the PGA clause, rather than recovery through base rates.

AIU states that Ms. Ebrey opines that prepayments could be reflected in a CWC analysis and AIU believes this makes sense. AIU says that in such an analysis, the Commission takes into account expense leads, or how many days between when a utility acquires goods or services and when it must make a cash payment. According to AIU, with a prepayment, the lead goes from positive to negative. AIU states that instead of, for example, 4 weeks after receipt, a utility might have to pay 2 weeks before receipt. AIU claims this 6 weeks‘ difference makes a difference to the utility, in that it represents 6 weeks of carrying cost on the cash.

In AIU's view, the evidentiary record supports the following options for recovery of the carrying cost of collateral: through the revenue requirement; recovery through the PGA mechanism; or as a line item in rate base. For the carrying cost of prepayments, AIU says the record supports recovery either through the revenue requirement, as a component of CWC, through the PGA mechanism, or as a line item in rate base.

b. Staff's Position

According to Staff, the financing costs of prepayments or interest are a component of a utility's cost of capital. Staff claims the interest expense associated with prepayments has not historically been considered an allowable operating expense in revenue requirement development. To the extent that the gas purchases have been included in storage gas included in rate base and a utility's cost of capital reflects the manner in which a utility finances rate base assets, Staff argues that the revenue requirements capture utility interest requirements. AIU claims that the carrying costs of the prepayments which are on the balance sheet of AIU are the costs on which AIU seeks a return. Staff claims that AIU witness Wichmann admitted that no such costs are specifically identified on the AIU balance sheets and that AIU did not actually transfer funds to pay interest, or carrying costs, associated with the financing of prepayments. (Staff Initial Brief at 171-172, citing Tr. at 734 and 737) According to Staff, those carrying costs are not actual out-of-pocket costs associated with gas purchases and therefore recovery would not be allowed through the PGA.

According to Staff, AIU claims that Ms. Ebrey suggests that AIU's CWC would be the appropriate option for recovery of the carrying cost of prepayments. Staff says that response was provided on March 31, 2008, six weeks prior to Staff's rebuttal testimony filing on May 14, 2008. Staff's final position on the recovery of any carrying costs associated with prepayments is set forth in rebuttal testimony and does not recommend recovery of these derived costs through CWC.

Staff states that recovery of costs associated with collateral postings for gas purchase contracts could be considered a case of first impression. Staff indicates that the posting of collateral associated with energy purchases was considered in the recent electric power procurement cases. In those proceedings, Staff says the costs associated with collateral postings were specifically identified as costs to be recovered under Rider PER for AIU. Staff opines that for the sake of consistency, the costs of collateral postings for the gas utilities should be treated in the same manner as the costs of collateral postings for the electric utilities.

Staff does not claim that such costs will be recovered through the PGA mechanism, but rather offers the recovery of the costs associated with collateral postings through the PGA mechanism as an option to be considered by the Commission. Staff states that this proceeding is to set base rates, not to consider specific costs to be recovered through other rate mechanisms. According to Staff, any costs to be recovered through the PGA would be considered in the annual reconciliation dockets to specifically review the costs AIU proposes to recover through the PGA rates.

AIU witness Moloney states that the counterparties will likely continue to seek to be fully secured until ratings return to investment grade levels. Staff states that it anticipates any rate increases determined in these proceedings would provide some level of comfort to the ratings groups who could raise the AIU credit ratings above investment grade levels. Staff adds that Standard & Poor's ("S&P") has already given AIU a positive outlook. Should AIU's credit ratings be upgraded and the counterparties no longer require to be fully secured, Staff says that ratepayers would be funding a cost that ceases to exist for the utilities, if AIU's proposal is approved. According to Staff, the option for the cost of collateral postings to be recovered through the PGA recovery mechanism, rather than through base rates, would provide some assurance that those costs would only be collected from ratepayers as they are incurred and not through the indefinite future. Staff recommends that the Commission disallow AIU's proposed pro forma adjustments to include as purchased gas expense an interest component related to cash collateral and prepayments for the gas utilities.

In its Reply Brief, Staff argues that collateral and prepayments are simply —opportunity" costs and not actual out-of-pocket costs incurred by AIU. Staff says AIU does not write a check to cover interest (carrying costs) related to prepayments. Staff also states that AIU's exposure will cease to exist when ratings return to investment grade levels. Staff complains that no provision is included in AIU's proposal should the ratings return to investment grade levels and exposure ceases to exist between rate case filings.

c. The AG's Position

AIU has included interest related to posting cash collateral and prepaying for gas purchases in pro forma test year gas O&M expenses calculated by taking the average balances of cash collateral and prepayments and applying the short-term rates by month to those average balances. The AG proposes two modifications to AIU's interest calculations. First, the AG says AIU's interest payments should be based upon the full 12 months of data available subsequent to the time debt ratings were downgraded. Second, in calculating the pro forma interest expense, the AG recommends that the latest known applicable interest rate be used rather than the month-by-month interest rates. The AG indicates that the effect of these adjustments is to decrease AmerenCILCO's gas expenses by $233,000, AmerenCIPS' gas expenses by $31,000, and AmerenIP's gas expenses by $391,000. AIU accepts the AG's adjustment.

d. Commission Conclusion

Having reviewed the parties' positions, the Commission finds Staff's arguments to be somewhat confusing and contradictory. In fact, it is not entirely clear what Staff recommends, although it seems to suggest that AIU should not be allowed to recover the costs of collateral and prepayments from ratepayers. The Commission first notes that while AIU may not write checks for collateral or prepayments, it does not write checks for depreciation expense or cost of capital. Those costs are reflected in base rates. Additionally, while there is no provision to change rates should AIU's credit ratings improve between rate cases, there is no provision to change any component of base rates if circumstances change between rate cases. In short, to the extent Staff argues that AIU should not be allowed to recover the cost of collateral or prepayments from ratepayers through base rates, that proposition is rejected. These appear to be prudent, reasonable costs incurred by AIU during the test year and it is appropriate for AIU to pass the costs on to ratepayers through base rates. The Commission finds the AG's recommended approach for calculating the annual interest cost associated with collateral and prepayments, to which AIU has agreed, to be reasonable for purposes of establishing rates in this proceeding, and it is hereby approved.

8. Reliability Initiatives

a. AIU's position

AIU seeks recovery of costs for reliability initiatives that consist of, among other things, projects for tap fusing, device inspection, lightning arresters, circuit inspection, multiple device interruption, improving worst performing circuits, underground cable replacements, and distribution service replacements. AIU claims that all of these projects are benefiting or will benefit customers.

Staff witness Ebrey and AG/CUB witness Effron propose to disallow AIU's costs related to reliability initiatives. Ms. Ebrey claims that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense and that such costs are not known and measurable. Similarly, Mr. Effron argues that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. In AIU's view, none of the reasons proffered by Ms. Ebrey and Mr. Effron provide a basis to disallow AIU's costs for reliability initiatives.

AIU argues that Ms. Ebrey is wrong that the Commission does not accept budgeted amounts for evidence supporting approved rate case expense. According to AIU, Ms. Ebrey characterizes AIU witness Getz‘s examples of past instances where the Commission has approved budgeted or estimated expenses as deficient without attempting to explain how. AIU contends that Ms. Ebrey completely fails to address the examples provided by Mr. Getz. Mr. Getz states that in the most recent AIU gas rate cases, rate case expense for all three utilities was based on estimates. AIU further asserts that in the prior electric rate cases, at least five adjustments were proposed based on budgets or estimates. According to AIU, these were: weather normalization adjustments, wage and salary adjustments to labor expense, pensions and benefits, tree trimming, rate case expense, and AmerenIP acquisition cost savings. AIU claims all five adjustments were contested by at least one party in the proceedings, and three of the five ultimately were set based on budgets or estimates.

In the last electric rate cases, AIU explains that for labor expense, incentive compensation was excluded while wage and salary expenses included 2006 budgeted percent increases. AIU says pension and benefits were based on 2007 actual expense. According to AIU, the Commission approved the 2006 budget amount for AmerenIP tree trimming costs and the Commission approved a combination of actual and estimated amounts for rate case expense. Finally, AIU says AmerenIP acquisition savings as budgeted through 2006 were included in the final determination of revenue requirement.

AIU contends that Ms. Ebrey also is mistaken in her belief that, because projects are currently —being identified and will be engineered and scheduled," that the costs can not be known and measurable. AIU argues that to the contrary, the broad scope of work to be performed has been identified and included in the pro forma adjustment. AIU claims calculations were made based on the type of work, the labor rates, materials, and equipment involved for the costs in the aggregate. AIU insists that the fact that some engineering and scheduling on these projects is ongoing does not mean that the projects are not expected to be completed. According to AIU, engineering often continues even after a project has started. In AIU's view, the costs are known and measurable.

AIU argues that Mr. Effron likewise fails to support his claim that there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. AIU contends that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring. AIU also believes the increases are determinable. AIU says reliability costs have grown from $816,000 in the 2006 test year to $2.2 million in 2007. According to AIU, the 2007 expenditures constitute a 265% increase from the test year expenses. AIU claims that it has already spent approximately $1.5 million related to reliability projects through March 31, 2008. AIU claims these expenditures are on track with budgeted amounts.

In AIU's view, Mr. Effron's claim that there is little or nothing in AIU's actual experience to support the level of reliability spending forecasted by AIU for 2008 is equally unavailing. AIU insists the 2008 expenditures are known, measurable, and on track with budgeted amounts. AIU argues that under the circumstances, past experience is not indicative of current and future levels of reliability expenditures. The Commission has placed increasing emphasis on reliability, and in response AIU claims to have raised the level of reliability spending. AIU asserts that unique coding has been implemented in the past few years to enhance tracking of specific reliability initiatives.

In its Reply Brief, AIU argues that although there may be some flexibility or shifting between items in the reliability plans, it is expected that AIU will still spend the budgeted amounts. In addition, AIU dismisses the AG's contention that there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. AIU claims it has provided evidence that increases in reliability expenditures are reasonably certain to occur, and, in fact, are occurring.

b. Staff's Position

Staff recommends disallowing AIU's proposed pro forma adjustments for reliability initiatives because they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that argument. Staff states that while the Commission may approve budgeted amounts in a rate case final order; those amounts have been analyzed by the parties to determine their reasonableness and are not approved simply because they have been budgeted. Staff asserts that there are wide variations between the amounts AIU budgeted for reliability projects in 2007 and the actual costs incurred. Staff claims there is a significant difference between the number of projects planned, or budgeted, as of July 17, 2007 and as of December 31, 2007.

Staff also says there have been multiple changes for each AIU division during a two-month period. Staff cites Section 287.40 of Part 287, which states in relevant part:

> These adjustments shall reflect changes affecting the ratepayers in plant investment, operating revenues, expenses, and cost of capital where such changes occurred during the selected historical test year or are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable.

According to Staff there is uncertainty associated with AIU's reliability projects; thus, AIU's pro forma adjustments should be disallowed.

In its Reply Brief, Staff asserts that AIU incorrectly claims Staff proposes to disallow costs associated with reliability initiatives. Staff says its proposal is to disallow the pro forma adjustment based on the increase of the 2008 budget over 2006 actual costs. According to AIU, the actual 2006 level of costs for reliability initiatives has not been proposed for disallowance by Staff. Staff says AIU claims that Ms. Ebrey does not explain how Mr. Getz's examples of approval of budgeted amounts in rate cases fall short. Staff claims, however, that Mr. Getz provided that explanation during cross-examination. (Staff Initial Brief at 175, citing Tr. at 576)

c. The AG's Position

According to the testimony of Mr. Stafford, AIU is experiencing increases in electric operating expenses to undertake and expand their reliability programs. To recognize the effect of these increases, AIU is proposing pro forma adjustments to increase the electric reliability expenditures from the amounts actually incurred in the 2006 test year to the forecasted expenditures in 2008 which increase AmerenCILCO's electric expenses by $2,526,000, AmerenCIPS' electric expenses by $1,763,000, and AmerenIP's electric expenses by $13,613,000.

In the AG's view, the problem is there is no evidence that AIU is actually experiencing increased spending of this magnitude on electric reliability programs. The AG claims AIU's actual spending on reliability programs in 2007 - the year immediately after the test year in these cases – was not materially different from what it was in the proposed test year. Mr. Getz cites the increases in reliability expenditures that have already taken place from the 2006 test year to 2007 and the first quarter of 2008, stating that spending on reliability projects increased from $816,000 in 2006 to $2.2 million in 2007 (representing all three electric utilities combined).

The AG believes that the percentage increase from 2006 to 2007 is not particularly meaningful because of the relatively low base off which the increase is calculated. Even assuming that the spending continues to grow at that rate, the AG states that the total for the three companies would be approximately $5.8 million in 2008, which would still fall well short of AIU's forecast of $18.7 million. Of the three companies, the AG claims only AmerenIP saw a significant increase in reliability spending from 2006 to 2007. Even if the spending in 2008 continues at the same rate as in the first quarter, the AG says spending for the full year would be $6 million, which would still be well short of AIU's forecast of $18.7 million.

In its Reply Brief, the AG says AIU mischaracterizes the AG's position when it states that AG/CUB witness Effron proposes to disallow all of AIU's costs related to reliability initiatives. The AG says Mr. Effron recommends only that the pro forma adjustments made for reliability initiatives through 2008 be disallowed. To the extent that actual spending in 2007 has increased beyond the 2006 test year levels, the AG includes those increases in its proposed adjustments. The AG recommends that the Commission reject those pro forma increases which it says are inconsistent with actual AIU experience. Even using the first quarter expenditures from 2008 as a guide, the AG claims AIU's total for the year would be only $7.2 million.

d. Commission Conclusion

Staff has proposed adjustments to disallow AIU's proposed pro forma adjustments for reliability initiatives since they are based on a 2008 budget and, in Staff's view, are not known and measurable. AIU argues that its budgets are known and measurable; however, Staff insists that the evidence provided in this case does not support that argument. Like Staff, the AG recommends that AIU's proposed pro forma adjustments for reliability initiatives be disallowed in their entirety. The AG argues that because neither the trend in actual reliability spending nor the actual spending rate in 2008 through the first quarter supports AIU's forecasts, there is little evidence that the actual reliability expenditures are increasing at anything like the rate being forecasted by AIU. Both Staff and the AG complain that AIU suggests they propose disallowing all costs associated with reliability initiatives when, in reality, they recommend disallowing AIU's proposed pro forma adjustment that would increase the test year level of these costs.

As an initial matter, it appears that AIU has, either intentionally or inadvertently, mischaracterized the Staff and AG proposals. Contrary to AIU's claim, Staff and the AG do not propose disallowing all costs associated with reliability initiatives; instead, they propose disallowing AIU's proposed pro forma adjustment to the test year level of reliability initiatives. Thus, the only question before the Commission is whether AIU's proposed pro forma adjustment should be reflected in operating expenses for the test year.

The Commission next notes that in her rebuttal testimony, Ms. Ebrey suggests that the vast majority of AIU's proposed pro forma adjustment for reliability initiatives is for pole replacements. The following table derived from Ms. Ebrey's direct and rebuttal testimony shows that her assertion appears to be correct:

Company	Proposed Test Year Reliability Initiatives	2008 Pole Replacements Budgeted
AmerenCILCO	$2,700,429	$2,545,592
AmerenCIPS	2,035,118	1,567,040
AmerenIP	13,982,361	12,151,845
Total	$18,717,908	$16,264,477

AIU has not explained why it is appropriate for pole replacements to be treated as an operating expense through so called reliability initiatives. In the Commission's view, pole replacements, as a general proposition, are capital expenditures for long lived assets which should be included in rate base. The table in Ms. Ebrey's rebuttal testimony indicates that between 2006 and 2008, AIU proposes to increase pole replacements treated as operating expenses from less than $300,000 actually incurred in 2006 (Staff Ex. 13.0 at 35) to over $16,000,000 proposed for 2008. The record of this proceeding does not support AIU's proposal to make proposed pro forma adjustments to electric operating expenses related to reliability initiatives. The Commission rejects AIU's proposed pro forma adjustments in their entirety.

9. Public Utility Fund Base Maintenance Contribution

a. AIU's Position

Section 2-203 of the Act requires certain electric utilities in Illinois to —contribute” their pro rata share of $5.5 million to the Public Utility Fund. AmerenCILCO, AmerenCIPS, and AmerenIP included expenses for the Public Utility Fund base maintenance contribution (—PUF BMC”) in test year revenue requirements. The total test year revenue requirement for this item for the three utilities is about $1.6 million.

Section 2-203 expires by its terms on January 1, 2009. AIU indicates that at the time a bill (Senate Bill ("SB") 1926, as amended by Senate Amendment 1) was pending in the General Assembly that would retain PUF BMC contributions until January 1, 2014. AIU says that despite the fact that PUF BMC contributions may be extended, Staff witness Ebrey proposes an adjustment to exclude expenses related to the PUF BMC from test year revenue requirements.

AIU believes Ms. Ebrey's adjustment to exclude PUF BMC expense is improper for at least two reasons. According to AIU, the adjustment violates the Commission's test year and pro forma adjustment rules. AIU says Section 287.40 of Part 287 provides for pro forma adjustments to historical test year data that are reasonably certain to occur within 12 months after the filing date of tariffs. AIU indicates that tariffs in this proceeding were filed on November 2, 2007 and argues that pro forma adjustments may extend to November 2, 2008. According to AIU, Staff's proposed adjustment relates to an expense item that will not be affected, if ever, until January 1, 2009. The adjustment, AIU contends, is outside the pro forma adjustment period and improper for that reason alone.

AIU also avers that Staff's adjustment is prohibited single-issue ratemaking. AIU argues that there are many different costs that could increase or decrease beyond the test year. AIU says that is the point of limiting the period for pro forma adjustments; to ascertain known and measurable adjustments to test year income and expense. According to AIU, Ms. Ebrey did not undertake a review to determine whether there was any legislation that would potentially increase AIU's costs after January 1, 2009. By recommending exclusion of a single expense item beyond the pro forma adjustment period, AIU asserts that Staff, in addition to violating test year rules, also inappropriately engages in single-issue ratemaking.

AIU says it recognizes the possibility that it may not incur PUF BMC expenses after January 1, 2009. In AIU's view, Staff's adjustment, however, fails to recognize that it is just as likely, if not more likely, that PUF BMC charges will not only be extended, but may be increased above the amounts required by current law. AIU says that in contrast to the one-sided nature of Ms. Ebrey's treatment of PUF BMC charges, it proposes a resolution that it believes is fair to both the companies and ratepayers. Specifically, AIU proposes that rates be set initially based on the level of PUF BMC expense included in Ameren Ex. 43.5. AIU suggests the Commission could authorize an across-the-board change to tariff rates effective January 1, 2009, to reflect PUF BMC funding requirements. If no contributions are required after January 1, 2009, the cost to ratepayers will be $0, AIU claims. AIU says that if contributions are required, those costs can be properly recovered in rates, dollar for dollar, based on whatever funding level is approved by the legislature. AIU says it would recover their actual PUF BMC contribution expense, no more and no less.

b. Staff's Position

Staff proposed an adjustment to reduce operating expenses for the PUF BMC, which was authorized by Section 2-203 of the Act, but expires on December 31, 2008. Staff states that if SB 1926, as amended by Senate Amendment 1, becomes a Public Act, the PUF BMC would be extended until January 1, 2014, and Staff's proposed adjustment would not be necessary. According to Staff, while AIU offers a number of criticisms of Staff's adjustment, none of those criticisms change the fact that Section 2-203 of the Act will be repealed absent further legislation. Staff asserts that its proposal provides the Commission an option depending on whether or not the legislature takes further action.

AIU points out that the amount of Staff's proposed adjustment does not consider that a portion of the total amount charged to Account 928 is not assigned to electric distribution operations. Staff agrees with this correction and reflects the adjusted amount in its proposed electric revenue requirements attached to its Initial Brief.

In response to AIU's arguments regarding pro forma adjustments, Staff contends that Section 287.40 addresses only pro forma adjustments that may be proposed by a utility company. Staff claims that Section 287.40 was never intended to limit Staff's ability to propose adjustments. Staff says that AIU's proposal would require ratepayers to pay for a soon to be non-existent PUF BMC, and if collected, AIU would have no obligation to remit the PUF BMC to the Illinois Department of Revenue. According to Staff, AIU wants the Commission to believe that the recovery of an expired cost accomplishes the requirement that all rates or other charges be just and reasonable as required by Section 9-101 of the Act.

Staff also disagrees with AIU that Staff's proposed adjustment to remove the PUF BMC is prohibited single-issue ratemaking. Staff states that single-issue ratemaking would occur if the Commission would, in a separate and presumably subsequent proceeding, consider or revise a single revenue or expense item. (Staff Reply Brief at 84, citing Business and Professional People for the Public Interest v. Illinois Commerce Commission, 146 Ill. 2d. 175, 244, 585 N.E.2d 1032) ("BPI II") In the instant proceedings, Staff indicates that AIU is seeking a general increase in rates under Section 9-201 of the Act. Staff says a general increase in rates is intended to consider all components of the ratemaking formula (i.e., revenues, expenses, rate base and rate of return). Therefore, Staff does not believe AIU's single-issue ratemaking argument is applicable.

c. Commission Conclusion

Based upon its review of the record and the parties' arguments, the Commission rejects Staff's proposal to reduce operating expenses associated with the PUF BMC. The Commission concludes that this possible change in the statute is not known with a sufficient level of certainty to incorporate the potential impact in this proceeding. Additionally, the Commission is concerned that the actual change, if it were to happen at all, would not take affect until January 1, 2009. As for AIU's alternative proposal, because it has rejected Staff's proposed disallowance, it seems moot. The Commission is also concerned that were it adopted, this proposal might be considered single-issue ratemaking.

10. Depreciation Life for Electric Distribution Equipment

a. AIU's Position

AIU presents the testimony of and a depreciation study prepared by Mr. Wiedmayer of Gannett Fleming. AIU asserts that the service life of utility property can be defined as the period of time from its installation until it is retired from service. According to AIU, the currently approved service life estimates were determined in conjunction with utility-specific service life studies that were performed by three depreciation experts at different firms for each electric utility. Mr. Wiedmayer proposes estimates based on his informed engineering judgment after an analysis of available historical service-life data related to the property, a review of management's current plans and policies, a review of the prior approved service-life estimates, and a review of service lives estimated by other electric companies. AIU submits that both the approved lives and proposed lives were reached using industry-standard methodologies, and while these studies revealed a wide range of estimated service lives, AIU suggests there is nothing unusual about this.

AIU complains that Staff's recommendation proposes no specific adjustment, but suggests that the depreciable lives for certain distribution plant accounts such as meters should be the same for all three utilities. Staff witness Rockrohr premises his recommendation on the observation that AIU is now operating under common management and, therefore, equipment is to be constructed and maintained to the same or nearly the same standards among all three utilities. AIU avers that Mr. Rockrohr reasons that the same equipment would remain in service the same number of years for each of AmerenCILCO, AmerenCIPS, and AmerenIP, and therefore should be assigned the same service life.

AIU states that absent common management, different depreciable lives were appropriate, and that it was reasonable for CILCO, CIPS, and IP to have different depreciable lives for distribution plant when the utilities were not affiliated. AIU submits that the mere fact of common management does not justify use of a single depreciable life for distribution plant.

AIU argues that management practice is just one factor to be used in determining depreciable lives, not the only or dispositive one. AIU claims that Mr. Wiedmayer's study showed other factors justified a wider range of estimated service life. According to AIU, his study determined that over 500 different models (or variations) of meters are in service on the AIU system, many of which were manufactured by a number of different companies, installed at different times, and subject to different conditions of service. AIU posits that Staff's recommendation is not based on a particularized study but is instead based on the fact that consolidation has taken place.

While Mr. Wiedmayer testified that he would expect the depreciable lives for certain plant accounts to be more similar in the future, he does not believe that a single depreciable life is warranted at this time. AIU notes that the utilities have only been affiliated since 2005, and submits that this is too short a period to have a material effect on the service lives of utility plant.

b. Staff's Position

Mr. Rockrohr recommends that AIU utilize a common depreciable life for electric distribution equipment if that equipment is used at all three utilities in an identical or nearly identical manner. Mr. Rockrohr acknowledges that the average age of equipment in the field at the three utilities is not identical. He explains, however, that looking forward, the service life of equipment at each utility will depend more upon the inspection and maintenance practices now in place than on the existing age of the equipment that is in the field. Mr. Rockrohr maintains that AIU should select a common depreciable life for equipment categories in which the equipment is utilized in an identical or nearly identical manner.

c. CUB's Position

CUB opposes AIU's recommendation to assign different service lives to distribution equipment that is used in an identical fashion in each utility‘s service areas in central and southern Illinois. CUB notes that Mr. Wiedmayer explains that the Commission approved the present depreciation rates for AmerenCILCO in 1994, for AmerenCIPS in 1992, and for AmerenIP in 1992. The depreciable lives of various categories of distribution equipment were set at those times. In those years, CILCO, CIPS, and IP were not affiliated with one another, and distribution facilities were not necessarily utilized and maintained in the same manner at each of the utilities. CUB notes that while it may have been reasonable that the same or similar equipment was assigned a different depreciable life at each utility in the past, the situation has changed. CUB submits that AIU now uses the same or nearly the same electric distribution construction and maintenance standards at each utility, and if the same equipment is to be installed and maintained in an identical manner at each utility then it is logical that the same equipment should, on average, remain in service the same number of years.

CUB argues that in order to maintain consistency of the calculation of the depreciable lives between similarly maintained equipment, the Commission should adopt Mr. Rockrohr‘s recommendation to amend AIU‘s depreciation schedules in a manner that provides the same depreciable lives for categories of distribution equipment that is installed and maintained in an identical fashion at each utility.

d. Commission Conclusion

The Commission notes that prior to the utilities' affiliation, different depreciable lives were determined as appropriate for each utility. The service life estimates were determined in conjunction with utility-specific service life studies that were performed by depreciation experts for each electric utility. These studies were based on available historical service-life data related to the property, a review of management‘s current plans and policies, a review of the prior approved service-life estimates, and a review of service lives estimated by other electric companies. The Commission believes that establishing single service lives for certain types of electric distribution utility property may be appropriate in the future but is not practical at this time.

Among other things, Staff and CUB fail to take note that many different depreciation lives were determined at different times and subject to different conditions of service at the time of installation. Thus, the Commission believes that the current approved service life estimates that have been assigned to plant property should remain. However, AIU is instructed in future rate cases to consider the possibility of assigning common service lives for plant accounts if they are utilized in the same manner at each utility in order to maintain consistency in the calculation of the depreciable lives among similarly maintained equipment.

11. Net Salvage Method for Depreciation Expense

a. AIU's Position

AIU notes that the general aim of depreciation accounting is to distribute the cost of fixed capital assets, less net salvage, over the estimated useful life of the assets in a systematic and rational manner. AIU witness Wiedmayer proposes using the traditional, accrual method for accounting for net salvage, by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. AIU points out that this is the approach used by the Commission for many years and by the majority of commissions in other jurisdictions. AIU submits that the fundamental goal of depreciation accounting is to allocate the full cost of an asset, including its net salvage cost, over its economic or service life so that utility customers will be charged for the cost of the asset in proportion to the benefit they receive from its consumption.

AIU argues that IIEC witness Selecky's proposed net salvage approach is a departure from Commission precedent, and is inconsistent with the approach used by the vast majority of state commissions. In light of this fact, AIU argues that one would expect Mr. Selecky to have compelling reasons before asking the Commission to alter its traditional practice. According to AIU, he presents none, however, and a number of other considerations counsel against adopting his approach.

First, AIU argues IIEC's proposed net salvage approach is inconsistent with the USOA. AIU notes that the USOA requires utilities keep their accounts on the accrual basis. AIU points out that utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. AIU submits that to only recognize salvage-related costs at the time any salvage-related dollars change hands would be to follow the —cash"basis of accounting, contrary to the instructions of the USOA.

According to AIU, Mr. Selecky's approach also violates the ratemaking principle of customer equity. AIU argues the principle of equity demands that the customers who enjoy a given benefit should pay their portion of the related costs, no more, no less.

AIU submits that while its approach would allocate net salvage costs associated with given assets to the customers being served by those assets, IIEC‘s approach would mismatch those who benefit from the net salvage costs with those who pay such costs.

AIU posits that IIEC‘s proposal would also recover the entire element of an asset‘s cost of service from customers that either received no benefit from the asset or only a portion of the asset‘s service value. AIU argues this is a violation of the principle of equity, and no different than requiring one generation of customers to pay the entire original cost of an asset that served many generations.

b. IIEC's Position

IIEC proposes an adjustment to depreciation rates because of what it views as the inequity of using net salvage cost calculations based on historical data. IIEC also objects to what it calls the inclusion of unproven, inappropriate inflation costs in depreciation rates. IIEC also argues that if the calculation of depreciation rates is not changed, it will fail to recognize the time value of money.

According to IIEC, AIU's depreciation expense should reflect the actual net salvage costs caused by ongoing transmission, distribution and general plant retirement, similar to the treatment afforded other expenses. IIEC argues the Commission should not approve AIU's proposed net salvage ratios, which it claims incorporate estimated inflation and ignore the purchasing power of the dollar. According to IIEC, AIU's estimates of net salvage are based on judgment, considering factors that are not well-defined and historical net salvage data that AIU admits were in some instances unreliable and limited. IIEC claims these deficiencies in the historical data led Mr. Wiedmayer to rely on net salvage estimates from other electric utilities. IIEC notes that the net salvage percentages that AIU proposes to incorporate in its depreciation rates are not exclusively based on AIU's own data, and IIEC argues that those percentages do not reflect AIU's actual experience.

IIEC contends that there is no dispute that inflation, which is at the core of IIEC's challenge to AIU's calculated depreciation rates, is a component of the net salvage estimates AIU has built into its proposed depreciation rates. IIEC says Mr. Wiedmayer used historical net salvage data to develop net salvage percentages by dividing the net salvage cost associated with retiring an asset by the original cost of the asset. IIEC insists that because the calculation uses nominal dollar amounts, net salvage cost is expressed in current dollars and the original cost of the asset is stated in the dollars for the year the asset was originally placed in service, inflation over the period between the two events is captured in the calculation. IIEC notes that the pre-inflation, nominal dollar figures associated with past investments are divided into the post-inflation, real dollar amounts for the cost of salvage. This calculation, IIEC argues, incorporates an unproven assumption that future inflation will occur at the same rate as past inflation, resulting in different ratios than actual experience would indicate. IIEC says the net salvage percentage is then incorporated in a depreciation rate that is applied uniformly over the useful life of the assets in the relevant account. According to IIEC, application of the single rate means that customers today will pay the same number of dollars as customers 30 to 40 years in the future, notwithstanding the difference in real purchasing values of those nominal dollars. IIEC contends that customers today will pay the same number of dollars as future customers despite the fact that current salvage expenses are much lower than the amounts collected from current customers and that without accounting for implicit inflation at a historical rate, which is inherent in the calculation. IIEC contends that the effect of these methodological flaws is an excessive level of depreciation expense.

IIEC argues that another adverse effect of the methodological flaws is unfairness in AIU's rates, and that the flawed calculations will foster significant inter-generational inequities. IIEC submits that under AIU's proposal, AIU customers will pay costs today that the utility may not incur for another 40 years. Moreover, IIEC argues in terms of real dollars, the uniform nominal amount that AIU would charge customers over the decades of assets' lives would actually require significantly less of future ratepayers.

c. The Commercial Group's Position

The Commercial Group agrees with Mr. Selecky that AIU has inflated depreciation expense by over-projecting net salvage expense, and that AIU proposes net salvage expense that is 2 to 5 times greater than AIU's current net salvage expense. The Commercial Group submits that AIU does so by projecting future inflation rates into salvage expense calculations. The Commercial Group avers that guessing and projecting the inflation rate for the next 30, 40, or 50 years into salvage expense is not likely to produce a result that follows actual salvage cost. The Commercial Group suggests this is demonstrated by the fact that actual current salvage expense is many times lower than the proposed salvage expense rate recovery. What this means, according to the Commercial Group, is that ratepayers in 2009 would pay the same actual dollar amount for the salvage expense of a set of electric poles to be replaced in 2040 as would a ratepayer in 2039; and considering the effect of inflation, means that the 2039 ratepayer would pay significantly less in real dollars for salvage of those poles in 2040 than would the ratepayer in 2009.

The Commercial Group submits that this represents a substantial intergenerational shift in depreciation expense that unfairly harms current ratepayers. Accordingly, the Commercial Group urges the Commission to adopt the lower depreciation rates as recommended by Mr. Selecky.

d. Commission Conclusion

The Commission does not concur with IIEC and the Commercial Group's proposal to depart from the Commission's current treatment of net salvage costs; specifically, using the traditional, accrual method of accounting for net salvage. Although there are some regulatory commissions that have moved away from the methods prescribed for depreciation, this Commission is not inclined to do so as the evidence does not show it is necessary. It has been appropriate to use the traditional method by allocating the cost to each year of the assets' service life rather than when the actual salvage-related costs are incurred. This method of depreciation allocates in a systematic and rational manner the service value of depreciable property over the service life of the property. IIEC's complaint that customers today will pay the same number of dollars as future customers represents a misunderstanding or misrepresentation of the purpose of systematic recovery of depreciation expense, which provides for rate recovery of long-lived assets over their expected useful life. In contrast, the net salvage approach advocated by IIEC and the Commercial Group would improperly push costs into the future that are more appropriately borne by current ratepayers. The Commission understands why such an approach may appear attractive in the short-run, but in the long-term it provides no benefit to ratepayers in aggregate. Further, contrary to the Commercial Group's assertion, the Commission concludes that AIU's reliance on some net salvage estimates from other electric utilities does not result in over-projecting net salvage expense relative to AIU's current net salvage expense. In conclusion, the accrual method for calculating net salvage is consistent with the Commission accounting practices for regulated utilities, has been accepted, deemed appropriate for years, and the Commission remains convinced that it is appropriate in this case.

12. NESC Violation Correction Costs After the Test Year

a. AIU's Position

AIU agrees to track costs associated with correcting NESC violations as Staff proposes, however, AIU opposes disallowance of those costs. AIU states that the Commission and Staff imposed a number of programs, initiatives, and other requirements of Ameren during the various acquisition dockets. In 2003, in Docket No. 02-0428, the Commission approved Ameren's acquisition of CILCORP, which included its operating utility subsidiary, CILCO. In 2004, in Docket No. 04-0294, the Commission approved Ameren's acquisition of IP. In 2005, AmerenUE transferred its service territory in Illinois to AmerenCIPS. AIU claims that assuming responsibility for unknown past violations of the NESC were not made part of the conditions of approval. According to AIU, it has fulfilled all of its responsibilities required in the Commission's acquisition dockets and it would be unfair and inequitable to impose, at this time, additional conditions of acquisition by holding AIU responsible for costs due to improper initial construction occurring prior to Ameren ownership.

AIU contends that a significant portion of the violations of the NESC were due to improper initial construction which occurred prior to Ameren ownership. According to AIU, it has made certain commitments in response to the NESC issues, including, an agreement to track all costs associated with NESC compliance, an agreement to forego current recovery of test year expenses that it has incurred for NESC compliance, an agreement to forego future recovery related to the replacement of otherwise grandfathered single cross-arms at railroad or interstate highway crossings, and an agreement to forego future recovery for the replacement of down guys or overhead guys that were improperly constructed after Ameren ownership.

AIU submits that it has put forth a fair and responsible proposal under which its shareholders will bear the costs associated with violations occurring after Ameren assumed ownership of AmerenCILCO and AmerenIP. AIU argues that disallowing all costs associated with correcting NESC violations due to improper initial construction by a previous owner should be rejected for various reasons. AIU avers that the proposed disallowance fails to find AIU's prospective investments are imprudent, and further posits that the proposed disallowance is at odds with the goals and objectives of the Act. AIU further submits that Staff witness Rockrohr's recommendation runs afoul of the Commission's long held policy of encouraging the acquisition of financially troubled utilities.

AIU argues that in determining whether future replacement costs should be recovered, the Commission's attention should focus on the decision of AIU management to make the prospective replacements and not on past construction efforts, and submits it would be improper to look at the conduct of previous owners. Moreover, AIU argues it does not seek recovery for NESC compliance measures in this proceeding. AIU notes that it has agreed to withdraw its request for recovery for those replacements proposed as test year costs. AIU avers that it is premature to conduct a prudency examination of its post-test year NESC compliance efforts, and therefore, Mr. Rockrohr's disallowance should be rejected as it is unripe. AIU also states that Mr. Rockrohr has failed to consider the prudency of making NESC required replacements.

AIU points out that Mr. Rockrohr's position is that the utility should bear all the consequence of all improperly constructed facilities, without regard for who constructed the facilities or the adverse financial impact on AIU. While Mr. Rockrohr believes it would be unfair for customers to bear any consequence of the improper initial construction, AIU submits that there is no evidence that he contemplated the impact of his recommendation on AIU's financial health. AIU contends that while Staff believes that AIU could have made itself aware of pre-existing NESC violations by inspecting ―some‖ of the distribution circuits, AIU submits that the facts suggest otherwise. AIU notes that the AmerenCILCO, AmerenCIPS, and AmerenIP service territories cover approximately 40,000 square miles and contain over 45,000 miles of distribution circuits supported by over 1,000,000 distribution poles. AIU submits that it is pure conjecture that spot checks would have uncovered the NESC violations at issue here.

AIU argues that it exercised due diligence and proceeded with its acquisitions based on the relevant information that was available at the time, and notes that the Commission approved each of the acquisitions with no findings of any shortcomings in Ameren's due diligence undertakings. AIU does not agree with Staff's assertion that in the event a utility system is not compliant with the NESC, corrective action must be taken pursuant to Commission Rule, 83 Ill. Adm. Code 305, "Construction of Electric Power and Communication Lines" ("Part 305"). AIU submits that Part 305 of the Commission's Rules is not as inflexible as Staff suggests. AIU notes that Section 305.130 provides for exemptions from NESC standards, and avers that the Commission can provide waivers of NESC standards or even modify the standards if the Commission so chooses.

b. Staff's Position

Staff recommends that AIU's costs associated with correcting certain NESC violations that exist due to improper initial construction should be disallowed from rate recovery. Mr. Rockrohr expresses concern that AIU intends to charge customers for re-constructing distribution facilities that CILCO, CIPS, and IP initially constructed improperly, and in the process earn a return on the costs associated with correcting the NESC violations. He further notes that as AIU's budgeting system does not separately track dollars associated with correcting NESC violations, he recommends that the Commission require that AIU track costs for correcting all NESC violations, and separately account for such costs. He also recommends that the Commission order that costs to correct violations that AIU itself caused not be approved for inclusion in rate base.

Staff argues that the alleged pre-existence of the violations prior to Ameren's ownership of the utilities is not a valid reason to pass these costs on to ratepayers. Staff submits that Ameren was not coerced or forced into purchasing CILCO and IP, and could have made itself aware of pre-existing NESC violations simply by inspecting some of the existing distribution circuits. Staff avers that as the merger of CIPS and UE was the catalyst for the formation of Ameren as a holding company, NESC violations within the operating area of CIPS can not be considered the fault of a prior owner. Mr. Rockrohr explains that based upon AIU's estimates, the compromise that AIU offers (whereby AIU would correct NESC violations consisting of single cross-arms at railroad and interstate highway crossings at shareholder expense) would equate to ratepayers paying for correcting about 95% of the NESC violations that are estimated to exist on AIU's system due to improper initial construction. Mr. Rockrohr posits that the compromise that AIU suggests is not reasonable, therefore he continues to recommend that the Commission order AIU to separately account for costs associated with correcting NESC violations that exist due to improper initial construction, and disallow those amounts from rates.

c. Commission Conclusion

As the Commission understands it, the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP constructed certain electric distribution facilities in a manner that are not in compliance with the NESC. Generally speaking, Staff objects to AIU passing along to ratepayers costs that are incurred to correct distribution facilities that were initially constructed in a manner that does not comply with the NESC. While it appears that AIU no longer requests to pass such costs on to ratepayers in this proceeding, AIU insists that it should not be responsible for the actions of the previous owners of AmerenCILCO, AmerenCIPS, and AmerenIP and should be allowed to recover from ratepayers the costs of remedying such NESC violations in the future.

Staff also recommends that the Commission order AIU to separately track and account for costs associated with correcting NESC violations that exist due to improper initial construction. AIU does not object to the recommendation. The Commission believes it is reasonable and it is hereby approved.

It appears that for purposes of establishing rates in this proceeding, there is no contested issue regarding proposed adjustments to rate base or operating expenses that flow from the reconstruction of electric distribution facilities that were improperly constructed in violation of the NESC. The Commission is, nevertheless, concerned about the position taken by AIU regarding this issue. The proposition that ratepayers should be responsible for paying the cost associated with improperly constructed electric distribution facilities as well as the cost of correcting the improperly constructed facilities is not one with which the Commission agrees. The suggestion that by disallowing from rates such costs constitutes an additional condition on any reorganization or merger is also rejected. In the reorganization or merger proceedings, AIU did not inform the Commission of the possibility that electric distribution facilities were not in compliance with the NESC and, as a result, the Commission did not consider the question or make any ruling on the matter.

Business decisions were made that resulted in CILCO, CIPS, and IP being owned by Ameren. The management and owners of Ameren, not ratepayers, made those decisions and they must live with the consequences. In this instance, the consequences will be that ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC. While there is no rate base or operating expense impact in this proceeding, AIU is on notice that the Commission has no intention of passing such costs on to ratepayers in future rate cases. As for AIU's suggestion that Part 305 is flexible, the Commission simply reinforces that it expects AIU to comply with all applicable Commission rules, including Part 305.

13. Gas Account 880 – AmerenIP

a. AIU's Position

Staff proposes to adjust the test year expense for AmerenIP‘s gas Account 880 "Other expenses" because Staff believes the expense is high when compared to other time periods. Account 880 includes "the cost of distribution maps and records, distribution office expenses, and the cost of labor and materials used and expenses incurred in distribution systems operations not provided for elsewhere, including the expenses of operating street lighting systems and research, development, and demonstration expenses." (USOA for Gas Utilities Operating in Illinois) Staff proposes that a 3-year average (2005-2007) be used instead, reducing AmerenIP‘s Account 880 expense levels by $1,026,000. According to AIU, Staff does not challenge the prudency of the expenditures shown in AmerenIP‘s Account 880. Instead, AIU says Staff only argues that the expense appears to be somehow —excessive.” AIU claims Staff‘s adjustment should be rejected for two reasons. First, Staff proposes an adjustment for an account that appeared ―high" but ignored countervailing adjustments for accounts that may have been lower in the test year than other years. Second, AIU claims to have shown that it is not reasonable to evaluate this account on an individual basis. AIU says account 880 is only one of a number of related transmission and distribution (―T&D") O&M accounts where costs can shift and vary year to year based on the level of activity and required work.

According to AmerenIP, the majority of O&M activities performed on its T&D facilities is very similar, and are managed, supervised, and performed by essentially the same resources, which include AmerenIP employees and third-party contractors. AIU claims the shift or change in costs between these accounts occurs based on the specific level of O&M activities needed and performed for the T&D main facilities in a given year. AIU states, for example, exposed pipe remediation, leak surveys, leak repairs, right-of-way clearing, main relocations, corrosion control, and painting are types of O&M work performed on T&D mains that may vary based on inspection cycle, facility condition, problem severity and magnitude, or highway department needs. Based on the classification of main, either transmission or distribution, and the type of work, operations or maintenance, AIU says the appropriate account is charged. AIU argues that it would be expected that, depending on the specific O&M needs, costs would not remain static among accounts.

AIU indicates that Mr. Lounsberry discussed Account 880, which is a sub-set of the larger grouping of T&D O&M accounts. To obtain a more accurate representation, AIU suggests that Staff should review the O&M costs for the T&D system in aggregate. In AIU's view, this approach provides a more accurate assessment of the reasonableness of the O&M costs versus evaluating individual accounts. During the period of 2005-2007, which includes the test year, AIU says the aggregate costs for AmerenIP's 800 series accounts have been reasonably consistent, with a slight upward trend. According to AIU, AmerenIP's average over this period for all T&D O&M costs is approximately $59.93 million, and no year deviates from this average by more than 6%. AIU argues that because it is reasonable to expect overall O&M costs to increase each year, the overall level of T&D O&M costs show that, when viewed in the aggregate, there is no basis for a concerns that T&D O&M costs are excessive.

AIU contends that Staff‘s logic could also be applied to individual accounts where 2006 represented the lowest level of expense for 2005-2007. AIU notes that Staff does not recommend increasing the amounts requested to any account that had the lowest expenditure in 2006 and higher expenses in 2005 and 2007. AIU claims that Accounts 878 "Meter and house regulator expenses" and 879 "Customer installation expenses" both have significantly less costs in 2006 than in either 2005 or 2007 and are below average for the 3 years. Using Mr. Lounsberry‘s analogy, AmerenIP asserts that since both of these accounts are lower than the three-year average for 2006, using averages rather than actual costs would require an increase rather than a decrease.

In addressing Mr. Lounsberry‘s concerns regarding cost levels in other T&D accounts, Accounts 856 "Mains expenses," 863 "Maintenance of mains," 874 "Mains and services expenses," and 887 "Maintenance of mains," AIU asserts that costs shift between the accounts, so that the appropriate way to determine if the O&M costs are just and reasonable is to evaluate and understand the trend for the overall cost of operating and maintaining the T&D system. In rebuttal testimony, Mr. Lounsberry indicated he no longer had any concerns regarding AmerenIP's Accounts 856, 863, 874, and 887 requested O&M levels. According to AIU, Staff has accepted that individual T&D accounts may vary from year to year, but that this does not mean the expense in any one account is unreasonable.

AIU asserts that Account 880 is one of the accounts from 850 though 894 that capture O&M costs for the overall T&D system. AIU says Account 880 can vary from year to year resulting in cost fluctuations in individual accounts and should be considered as part of the aggregate. AIU believes these T&D O&M costs, including costs of Account 880, must be considered at the aggregate level, as opposed to the individual account level, to accurately evaluate the O&M costs for the T&D system.

b. Staff's Position

Mr. Lounsberry recommends a reduction of $1,026,000 to AmerenIP's requested test year amount for Account 880. He states that AmerenIP requested $9,505,000 for its Account 880, but that his review found that AmerenIP's test-year expense was higher than any other period reviewed for this account. Mr. Lounsberry's review was limited to the three-year period 2005-2007, because in 2005 IP was transitioning to AIU's accounting system. Therefore, Staff believes any expense data for IP prior to 2005 uses a different accounting system and will not necessarily correlate to the AIU accounting system.

AIU responds that it is not reasonable to evaluate this account on an individual basis. AIU witness Colyer states that Account 880 is only one of a number of related T&D O&M accounts where costs can shift and vary year to year based on the level of activity and requirement work. Instead, Mr. Colyer indicates that Account 880 should be considered as a variable part of the aggregate 800 series of O&M accounts for the T&D system. Mr. Colyer also notes that Mr. Lounsberry's proposal does not indicate AmerenIP's proposed Account 880 amount was unreasonable, but that the requested amount was just higher than other years.

Mr. Lounsberry does not agree with Mr. Colyer's assertion that the aggregation of about 40 different accounts will demonstrate the reasonableness of any individual account. However, in order to provide a complete review, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Staff says this review indicates that when using the same 3-year period (2005-2007) that Mr. Lounsberry had used to normalize the individual Account 880 amount to review the aggregation of the 40 different 800 series accounts, his analysis came up with virtually the same result as looking at Account 880 individually. Specifically, Staff claims the 3-year average from aggregating the Account 800 series of T&D O&M amounts shows AmerenIP's test year request was about $940,000 above that average. According to Staff, the review of the aggregate accounts also supports Mr. Lounsberry's original adjustment to reduce the Account 880 expense amount by $1,026,000.

c. Commission Conclusion

The Commission has reviewed the record and the parties' arguments regarding the proper costs to include in Account 880. As Staff's analyses demonstrate, AIU's arguments do not withstand scrutiny. Whether Account 880 is analyzed individually or with the other O&M accounts for T&D in aggregate, the test year amounts are abnormally high by approximately $1 million. As a result, the Commission finds Staff's proposal to reduce the amount of Account 880 costs that AmerenIP may pass along to ratepayers by $1,026,000 reasonable and it is hereby adopted.

14. Gas Accounts 830 and 834 - AmerenCILCO

a. AIU's Position

With regard to gas Accounts 830 "Maintenance supervision and engineering" and 834 "Maintenance of compressor station equipment" for AmerenCILCO, Staff proposes to adjust the expense levels in these accounts to reflect an average of the expenses over a 5 year period from 2003- 2007. According to AIU, no party has suggested that the expenses in these accounts were not prudently incurred; rather, Staff suggests that the test year levels of these expenses were excessive. AIU maintains that the reason for the variation of costs from year to year in Accounts 830 and 834 is that internal labor costs can shift between accounts from year to year as a result of the cyclical nature of maintenance activities, capital projects, and the type of activity being performed. AIU asserts that it is not appropriate to consider increases in costs recorded to Accounts 830 and 834 in isolation. Rather, AIU says accounts 830 and 834 must be considered in the context of the combined gas storage accounts.

According to AIU, Staff witness Lounsberry's logic could also be applied to AmerenCILCO gas storage accounts where 2006 represented the lowest level of expense in the 2005-2007 periods. AIU relates that Mr. Lounsberry does not recommend increasing the amounts requested for any accounts that had the lowest expense in 2006 and higher expenses in 2005 and 2007, such as Account 816 "Well expenses" where the expenses were $211,724, $141,028, and $179,197 respectively for 2005-2007. AIU complains that Mr. Lounsberry also does not explain why the variations in Accounts 830 and 834 were unusual or what, if anything, made the test year expense unreasonably high.

To properly capture these variations, AIU claims Mr. Lounsberry would need to average costs for all related accounts, not just the ones that were higher. According to AIU, overall expense for O&M for gas storage for AmerenCILCO is relatively stable over time. AIU claims the low expense level in 2007 was due to an unusual capital expenditure amount for 2007 that shifted resources from O&M to capital expenditures. In AIU's view, this shows that the variance over the years to accounts like Accounts 830 and 834 represents shifts of expenditures between accounts, but not an overall increase in O&M expense.

On rebuttal, Mr. Lounsberry argues that using the 2003-2007 period for AmerenCILCO's Accounts 830 and 834 shows the aggregate amounts for 2004 and 2005 are the highest of the period. AIU contends that the 2005–2007 data for the combined gas storage accounts is more current and therefore more representative of expected ongoing costs going forward, because it reflects cost increases and the impact of the mergers of AIU. AIU believes the use of the 2005-2007 time periods to compare aggregate gas storage account costs is reasonable. AIU argues that using Mr. Lounsberry's analysis, one could pick an individual account in the test year with a lower than average balance and determine that an increase is actually required rather than a decrease.

b. Staff's Position

Mr. Lounsberry recommends a reduction of $25,000 to AmerenCILCO's requested test year amount for Account 830. He explains that AmerenCILCO's test year expense was the second highest expense over the 5 historical years reviewed and that AmerenCILCO's expenses associated with this account varied significantly during the 5 historical years. He also recommends a reduction of $54,000 to AmerenCILCO's requested test year amount for Account 834. AmerenCILCO requested $89,000 as its Account 834 test year amount, which Staff notes was the highest expense over the five historical years reviewed and that expenses associated with this account varied significantly during the 5 historical years.

Mr. Lounsberry does not agree with AIU's assertion that the aggregation of the gas storage accounts demonstrates the reasonableness of any individual account. In order to provide a complete review, however, Mr. Lounsberry conducted such an aggregation for comparative purposes only. Instead of limiting that review to the 3-year period that AIU used, Mr. Lounsberry actually used the full 5 years' of historical information that he had relied upon in making his initial adjustment. According to Staff, the combined gas storage accounts revealed that the total expenses were as follows:

2003	$ 909,000
2004	$ 888,000
2005	$1,463,963
2006	$1,419,581
2007	$1,151,275

Staff states that the years 2005 and 2006 had the highest aggregate totals by a significant amount. Therefore, Staff concludes that the aggregate accounts supports Mr. Lounsberry's proposal to reduce AmerenCILCO's Account 830 test year expense amount by $25,000. Staff also believes the aggregate of the accounts supports Mr. Lounsberry's proposal to reduce the Account 834 expense amount by $54,000.

AIU argues that use of the 2005-2007 data for the combined storage accounts is more current and therefore more representative of the expected on-going costs because it reflects cost increases and the impact of the AIU mergers. AIU also asserts that the O&M expense for gas storage is relatively stable over time and that the variances over the years to an account like Account 830 represent shifts in expenditures between accounts, but not an overall increase in O&M expense.

Staff says it analyzed the individual Account 830 costs over the period from 2003-2007. Staff claims this analysis demonstrates that at least for Account 830, the 2005-2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year. According to Staff, the expenses over the 2003-2007 time period were as follows:

2003	$ 8,000
2004	$65,000
2005	$34,000
2006	$58,000
2007	$0
Average	$33,000

In Staff's view, AIU did not demonstrate why the proposed test year amount for Account 830, $58,000, would be just and reasonable.

Similarly, Staff believes the Account 834 costs information for the years 2005 - 2007 data is not representative of the expense amount that AmerenCILCO requested for the 2006 test year:

2003	$ 3,000
2004	$20,000
2005	$29,000
2006	$89,000
2007	$33,000
Average	$34,800

According to Staff, AIU fails to demonstrate why the use of the year 2006 amount for Account 834, $89,000, would produce just and reasonable rates.

c. Commission Conclusion

Having reviewed the record and the parties' arguments, the Commission finds Staff's proposed reductions to Accounts 830 and 834, of $25,000 and $54,000, respectively, to be appropriate. While AIU's argument that gas storage cost accounts should be reviewed in aggregate has some appeal, a 5 year average of the aggregate gas storage cost accounts might suggest a reduction of over $250,000. In the

Commission's view, Staff's proposed reductions, while arguably conservative, are reasonable and should be adopted.

15. Gas Account 823 - AmerenIP - Hillsboro

a. Staff's Position

AmerenIP seeks to include in rates as an operating expense an annual inventory adjustment of $1,439,000 at the Hillsboro Storage Field. Staff witness Lounsberry recommends that the Commission deny recovery of this amount. His primary reason for making this recommendation is his belief that AmerenIP, due to the various historic problems it has experienced at the Hillsboro field, can not yet reliably make use of the reservoir information to determine any needed adjustments to the field's inventory.

Mr. Lounsberry states that one of the primary means that a utility has to oversee the operation of its storage field involves comparing the field's inventory to the pressure of the gas in the field. He claims that AmerenIP's failure to operate the Hillsboro field with a constant inventory volume since the field was expanded in 1993 causes a situation where the use of normal oversight practices is not reliable. Staff asserts that this concern is shared by AmerenIP. Staff cites a November 20, 2006 report that Staff says, as a result of replacing the 5.8 Bcf of inventory over the prior 3 years, the hysteresis curve is not stable enough to aid in determining a gas loss correction. According to Staff, AmerenIP personnel estimated that after three years of cycling the reservoir at a constant working gas volume, the reservoir would stabilize and the hysteresis curve will be helpful in quantifying gas loss volumes.

AIU argues that in 2006, AmerenIP developed an engineering estimate of the magnitude of losses at Hillsboro. AIU reports that this estimate showed that 200,000 Mcf was appropriate to maintain Hillsboro performance. Subsequent to developing the 2006 estimate, AIU states that AmerenIP conducted additional analysis in 2007 that verified the 2006 estimate was appropriate. According to Staff, in making this latter calculation, called the Tek Methodology, AmerenIP compared the total gas in the reservoir at the end of the 2001 withdraw season to the total gas in the reservoir at the end of the 2006 withdraw season. This calculation was then divided by 5 (for five seasons between the values) and showed a loss amount of 2.29 Bcf, or a loss of about 460,000 Mcf per cycle, or roughly double the 200,000 Mcf loss correction AmerenIP calculated. AIU also indicates that the same calculation was made between 2001 and 2008 and showed about a 340,000 Mcf gas loss per cycle.

Mr. Lounsberry believes that AmerenIP is making its conclusion based on data that compares data points for a time period when the Hillsboro field's inventory was greatly reduced to a more recent period for when Hillsboro had additional inventory. Staff believes the timing of AmerenIP's calculation is causing it to rely upon an apples-to-oranges comparison rather than a comparison that would take place once AmerenIP replaced the inventory in the Hillsboro field. Staff notes that AmerenIP's calculation compared 2001 to 2006 data as well as 2001 to 2008 data. Staff states that AmerenIP had previously concluded that the inventory balance that it maintained at the Hillsboro field was overstated by 5.8 Bcf as of November 30, 2003. AmerenIP replaced this inventory over a 3-year period, 2003-2005. Staff says AmerenIP also claimed to have found a 1.1 Bcf error that it returned to the Hillsboro field during the 2007 injection season. Therefore, Staff argues, AmerenIP is using inventory numbers for 2001 that bear no relationship with either the 2006 or 2008 values due to the extremely large amounts of gas replaced during the intervening period.

Staff also contends that in 2001, the Hillsboro field was not even functioning properly. Staff states that AmerenIP had reduced the peak day capacity rating of the Hillsboro field to 100,000 Mcf per day from 125,000 Mcf per day. Staff also says that due to the inventory shortfall, the Hillsboro field could only produce a fraction of the seasonal quantities it was designed to produce, 2,916,351 Mcf instead of 7,600,000 Mcf or 38.37% of its design total. According to Staff, AmerenIP's attempt to use 2001 data for comparative purposes does not make sense and should be disregarded.

AIU agrees that AmerenIP's comparison occurred during periods when inventory was reduced. AIU also provides the same Tek Methodology analysis, but limited it to comparing the 2006 to 2008 time period. AmerenIP claims this second comparison is generally in agreement with the original 2001 to 2006 comparison. AmerenIP insists that this analysis supported its decision to add about 200,000 Mcf of inventory to the Hillsboro field in 2006.

Staff maintains that the calculation comparing 2006 to 2008 information, still did not account for the 1.1 Bcf that was added into the Hillsboro field inventory in 2007. Staff also states that AmerenIP's analysis relies upon the gas volume in the field at the end of the withdrawal cycle. According to Staff, a warmer winter season makes it more difficult for a utility to withdraw gas storage volumes from its owned and leased storage fields. Staff argues that, in general, warmer weather creates a situation where more gas is remaining in the field then the utility had planned. Mr. Lounsberry says the 2006 test year conditions were warmer than normal. Staff claims AIU also agrees that winter season temperatures can impact the level of gas that it can withdraw from storage. Staff complains that AmerenIP's calculation does not take into account any temperature conditions. In Staff's view, AmerenIP's analysis is overly simplistic and limited for use at a storage field that has not experienced significant historical inventory losses. Staff does not believe AmerenIP's analysis provides a conclusive demonstration of the need for an annual inventory adjustment at the Hillsboro field.

Mr. Lounsberry also expressed concern that AmerenIP had never determined the need to make an annual inventory adjustment for the Hillsboro field prior to the 2006 test year. His concern is that there was no history of a similar expense and thus no history of a need to make an annual inventory adjustment at the Hillsboro field. AIU agrees that 2006 was the first occasion an annual inventory adjustment was made to Hillsboro, although AIU claims to have made inventory adjustments for a number of years at other storage fields. AIU states that AmerenIP intends to make a similar adjustment for Hillsboro in 2007.

Staff notes that AmerenIP has recently replaced a significant amount of gas at the Hillsboro field. Staff says AmerenIP's replacement gas represents 96% of the gas volume that the Hillsboro field was designed to withdraw during the winter season. Mr. Lounsberry expresses concern that AmerenIP was not making use of the reservoir model that was discussed extensively during IP's last rate proceeding, Docket No. 04-0476. Staff is concerned that such a valuable resource was not used as part of AmerenIP's calculations in this proceeding, especially given the time and money spent to develop this model. Mr. Lounsberry expected AmerenIP to make use of it to develop or support inventory numbers versus calculations based on comparing inventories between two inconsistent time periods. AIU claims the model was not available to evaluate Hillsboro because in 2005, AmerenIP made the determination to not further pursue modeling until a complete metering data set had been established in the reservoir simulator. AmerenIP did not begin to rebuild this database in preparation for resumption of modeling the reservoir until the summer of 2007. Staff complains that it is not clear why AmerenIP was unable to update the metering data set in a more timely fashion.

According to Staff, AmerenIP suggests that Mr. Lounsberry's recommendations are inconsistent with prior proceedings, Docket Nos. 03-0699 and 04-0677, wherein Staff noted that IP should have begun replacement of inventory at the Hillsboro storage while continuing to pursue its investigation as to the cause of the inventory shortfall. Staff says that in those proceedings it argued that had IP been aware of that error in a more timely fashion, it should have replaced some of that known inventory shortfall caused by the metering problem while continuing to investigate if the Hillsboro field had additional problems. Staff fails to see any connection between the instant proceeding and those prior cases. Staff claims that Mr. Lounsberry's testimony and the issue at hand is whether AmerenIP can justify the volume and value of the inventory adjustment that it wishes to make for the Hillsboro field.

b. AIU's Position

AmerenIP proposes an annual inventory adjustment to Account 823 of $1,439,230 for the Hillsboro Storage Field (―Hillsboro"). The adjustment represents AmerenIP's determination to inject additional gas at Hillsboro. AmerenIP claims the proposed adjustment is conservative and based on the best data available to the AmerenIP.

In 2006, AIU states that AmerenIP developed an engineering estimate of the magnitude of gas losses at the Hillsboro field. The results of the estimate indicated that a 200,000 Mcf injection of gas was appropriate in 2006 to maintain Hillsboro's performance. Subsequent to developing the estimate, AIU indicates that in 2007 AmerenIP conducted an additional analysis, using information obtained during the next inject/withdraw cycle, verifying that the estimate it used in 2006 was supportable and prudent. According to AmerenIP, the engineering principles utilized for the 2007 analysis included the Tek Methodology, an analysis of the hysteresis plot for the field, and a review of field withdrawal performance. AIU claims these are all commonly accepted gas storage reservoir engineering practices.

An additional analysis of reservoir performance, AIU adds, was performed in the spring of 2008 to investigate what impact the injection of additional gas has had on the delivery performance of the Hillsboro field. For this analysis, AmerenIP re-estimated gas loss using the Tek Methodology. According to AmerenIP, the decrease in estimated gas loss from the 2001to 2005 analysis and the 2001to 2008 analysis indicates that the 200,000 Mcf gas loss adjustments that were made in 2006 and 2007 have had a positive impact on maintaining reservoir deliverability. In AIU's view, these analyses showed that AmerenIP's 200,000 Mcf estimate of the gas loss is reasonable and prudent.

AIU argues that there is no dispute that the lost gas should be replaced and Staff does not suggest otherwise. AIU contends that AmerenIP's analysis of the data supports the amount of gas loss and the need for replacement, based on the Tek Methodology. Reinjection of gas to replace lost gas before completion of a thorough engineering analysis of the reservoir response is, AIU claims, consistent with Staff's position in past cases. According to AIU, without the reinjection of the lost gas, field performance at Hillsboro would be at risk, and the field might not be able to cycle the gas required to best meet customer needs. AmerenIP expects that Hillsboro deliverability would decline by approximately 200,000 Mcf per year without reinjection, impacting daily deliverability at the year end. AmerenIP claims that not reinjecting could also cause increased water production and possibly increased H_2S production, further decreasing the reliability of the field. AIU says these factors would ultimately be reflected as a higher cost for ratepayers.

Staff opposes the annual inventory adjustment based primarily on concerns about the reliability of the data supporting the adjustment. Staff believes that AmerenIP does not have sufficiently reliable information about Hillsboro, and can not perform the necessary engineering studies to quantify the gas loss. AIU says Staff recommends doing nothing at this time to address the gas loss issue. AIU maintains that inaction would not be appropriate. AIU believes that AmerenIP should take steps to address the performance of underground fields, such as injecting replacement gas, to maintain reliable service from its storage fields. AIU relates that AmerenIP has calculated annual inventory losses supporting the inventory adjustment at Hillsboro.

At Hillsboro, AIU and Staff acknowledge that an adequate stable inject and withdraw history dataset has not been established that would allow a detailed analysis using hysteresis techniques. AIU asserts that any correction must be based on an engineering estimate, or rely on other sound engineering principles and practices other than hysteresis techniques. AIU asserts that AmerenIP is not required to support its adjustment on a specific type of analysis just because Staff would prefer it. AIU claims that AmerenIP properly relies on the available data, which reasonably supports the adjustment.

AIU argues that Staff's position on the deterioration of storage field performance is inconsistent with a disallowance of an annual inventory adjustment for Hillsboro. AIU asserts that on the one hand Staff supports injecting additional gas to maintain reservoir performance, but on the other hand disallowing the cost of the actions taken by AmerenIP to maintain that performance. It is AIU's opinion that AmerenIP has utilized the best data that is available to make a sound engineering judgment regarding the Hillsboro lost gas adjustment and AmerenIP has taken proactive steps to maintain the field's deliverability.

According to AIU, Staff has recommended, in previous proceedings, that a gas utility take action to correct an inventory shortfall even when data is not complete. AIU says that in Docket Nos. 03-0699, 04-0677, and 05-0743, Mr. Lounsberry argued that IP did not act fast enough to replace the gas at Hillsboro that was no longer in the field. In those cases, AIU says Mr. Lounsberry's position was that the utility should have been replacing inventory while continuing to pursue its investigation as to the cause of the inventory shortfall. In this case, Mr. Lounsberry states that AmerenIP should not use available data to proceed to make an adjustment, even though AmerenIP has calculated its inventory adjustment based on the best available data and is continuing to gather data to improve the estimate.

With regard to Staff's specific concerns, AIU believes these have been adequately addressed. In response to Staff's concern that comparing 2001 data to 2008 data is not appropriate, AIU says that AmerenIP undertook an analysis using data from 2006 - 2008 instead of comparing to 2001. AIU claims the results of this analysis were consistent with the analyses comparing 2001 to 2006 and 2008, and showed that there is an annual gas loss occurring at Hillsboro of slightly less than 0.5 Bcf per year. According to AIU, the original calculations utilizing a 2001 data comparison indicate that from the time period from 2001–2006, the gas loss was 468,000 Mcf per year and from 2001–2008, the gas loss was 337,000 Mcf. AIU insists that AmerenIP is justified in making a conservative adjustment of 200,000 Mcf per year.

AIU reports that the Hillsboro field cycled 6.7 Bcf of gas in 2005–2006 and 6.6 Bcf in 2007–2008. AIU claims that if AmerenIP had not injected an additional 200,000 Mcf during the 2006 and 2007 injection seasons, it is reasonable to assume AmerenIP would not have been able to withdraw roughly equal amounts of gas during the two seasons that are compared.

Mr. Lounsberry also opposes the annual inventory adjustment at Hillsboro based on the concern that annual adjustments were not made before the 2006 test year, raising concern that there is not a history of similar expenses for Hillsboro. AIU states that Mr. Lounsberry is correct that 2006 is the first occasion that an inventory correction was made to Hillsboro in recent history. AIU claims that AmerenIP has made corrections to storage field inventories on an as-needed basis for many years and has performed inventory corrections on an ongoing basis. In AIU's view, the fact that the first correction at Hillsboro occurred in 2006 does not mean the adjustment is not just and reasonable.

According to AIU, Mr. Lounsberry is correct that the reservoir model would be an appropriate method to determine gas losses. AIU says the reservoir simulator was not available to evaluate Hillsboro because the model data deck had not been updated to include the withdrawal metering corrections from 2000-2007. AIU adds that in 2005 the determination was made not to further pursue modeling until a complete metering data set had been established for the reservoir simulator. AIU states that in the late summer of 2007 AmerenIP began to rebuild the database in preparation for resumption of modeling of the reservoir and that project is still in progress. AIU contends that because the model was not available, other sound engineering techniques were used to determine the gas loss. After the revised data deck is built, AIU states that AmerenIP will model the reservoir and present the results to Staff. AmerenIP recognizes that it is proceeding with modeling utilizing adjusted data, rather than actual field data, but insists the adjusted data is sufficient to support the annual inventory adjustment.

c. Commission Conclusion

AmerenIP proposes an annual inventory adjustment to Account 823 of $1,439,230 for the Hillsboro Storage Field. AIU insists the proposed adjustment is conservative and based on the best data available. AIU contends further that the fact that Staff would prefer some other type of data or study to support the adjustment is not a basis for rejecting the adjustment. Staff's primary reason for opposing the adjustment is due to the various historic problems AmerenIP has experienced at the Hillsboro field. Staff does not yet believe that AmerenIP can reliably make use of the reservoir information to determine any needed adjustments to the inventory at the Hillsboro field.

The Commission again observes that this issue is similar to two issues previously addressed regarding lost gas at the Hillsboro field. In the other two instances, AmerenIP asserts that there has been lost base gas, it has estimated the volume of lost gas, and requests authorization to include the additional base gas in rate base. In this instance, AmerenIP asserts there is lost gas at Hillsboro, it has estimated the volume of lost gas, and it wishes to recover the cost of replacing the lost gas through operating expenses. In all three instances, Mr. Lounsberry objects to AmerenIP's request. Mr. Lounsberry again insists, among other things, that AmerenIP has failed to adequately demonstrate that its estimate of the volume of lost gas is reasonable or appropriate. Just as it did in Docket No. 04-0476, as well as for the two previous lost gas issues in this case, the Commission finds Mr. Lounsberry's expert testimony to be convincing. The Commission concludes that AIU failed to adequately demonstrate that AmerenIP's estimate of the lost gas is reasonable. As a result, the Commission adopts Staff's recommendation and AmerenIP's request to recover the replacement gas through Account 823 is denied. In the Commission's view, these three decisions regarding lost gas at Hillsboro are consistent with, and are required by, the appellate court decision discussed earlier in this Order.

16. Gas Accounts 920-923 - AmerenIP

a. The AG and CUB's Position

The AG and CUB propose an adjustment to reduce the pro forma AmerenIP A&G expenses by $7,736,000. In analyzing the expenses associated with the general administration of operations, AG/CUB witness Effron believes that it is appropriate to consider expenses charged to Account 923 "Outside services employed" together with expenses charged to Accounts 920-922, which are compensation to management employees and other expenses of administrative departments. Mr. Effron testifies that expenditures charged to Account 923 for outside professional services can be similar in nature, except the expenditures are to persons who are not employees. For example, salaries of attorneys or engineers who are employees would be charged to Account 920, while expenditures on outside attorneys or engineering consultants would be charged to Account 923. In both of these cases, the AG and CUB say the expenses relate to the administration of the operations of AIU and, to some extent, may be interchangeable. Mr. Effron proposes to adjust AmerenIP's gas test year A&G expenses charged to Accounts 920-923.

The AG and CUB point out that in 2004, the test year in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the pro forma expenses included in Accounts 920-923 by AmerenIP were $22,259,000. The Commission eliminated approximately 30% of the AmerenIP A&G expenses from the revenue requirement in that case. The AG and CUB say the Commission's A&G adjustment was not broken out by account, but assuming that the adjustment was spread evenly over all the A&G accounts, the AmerenIP revenue requirement in its last rate case reflected an allowance of $15,476,000 charged to Accounts 920-923.

The AG and CUB claim the A&G expenses charged to Accounts 920-923 in the 2006 test year in the present case significantly exceed the expenses found to be reasonable by the Commission in AmerenIP's last rate case. Thus, the AG and CUB believe that the expenses allowed by the Commission in the prior rate case form a reasonable basis for A&G expenses to be included in the AmerenIP revenue requirement in this case. Thus, Mr. Effron's recommendation is to reduce the pro forma AmerenIP A&G expense by $7,736,000 as reflected in AG/CUB Ex. 4.0 at 9-10.

b. AIU's Position

AIU believes an adjustment to the A&G expense is not warranted. AIU asserts that Mr. Effron's methodology for determining his proposed adjustment to the A&G expense is flawed. AIU witness Adams explains that, in calculating his adjustment, Mr. Effron uses as a starting point the level of A&G expenses charged to Accounts 920 through 923 approved by the Commission in AIU's last gas rate cases, which used a 2004 test year. Mr. Effron calculates this amount by taking the total of A&G costs related to Accounts 920 through 923 times the percentage of costs that were disallowed. AIU says he then escalates this last approved level of A&G expenses charged to Accounts 920 through 923 by 3% per year to reflect inflation. The end result of Mr. Effron's initial adjustment is the proposed disallowance of $19,794,000 of A&G expenses for AmerenIP. AIU says this is the difference between the amount approved in the last rate case, escalated by inflation, and the expenses included by AmerenIP in this case, for Accounts 920 through 923.

AIU argues that the Commission has rejected the notion that inflation between rate cases is a better indication of test year expenses than the actual costs themselves. AIU says Mr. Adams' rebuttal testimony explains the modification of accounting practices implemented after the acquisition of IP by Ameren. AIU points out that thereafter, Mr. Effron reduces his proposed adjustment by $7.7 million. AIU claims the actual level of AmerenIP's A&G expenses have been fully justified between the AMS study which Mr. Adams sponsored and through his testimony on the topic of A&G expenses.

AIU claims Mr. Adams explains that the comparison of the level of expenses between 2004 and 2006 for AmerenIP produces specious results because during the transition of ownership, AIU received no allocated costs from either its former owner or from AMS. Therefore, AIU asserts that the true cost of services provided is not reflected in the 2004 expense levels.

c. Commission Conclusion

The AG and CUB are correct in asserting that the A&G expenses authorized by the Commission for Accounts 920-923 in the 2004 test year are significantly different than those requested by AIU for the 2006 test year in the present case. However, it appears that the AG and CUB do not adequately consider various changes that have occurred, which may have contributed to an increase in the A&G expense from the last rate case. AIU also provided the Commission with an AMS cost study detailing the test-year 2006 A&G expenses, which the Commission must consider in this case. In addition to inflation, which the Commission believes is a relevant factor, actual costs must also be considered, and AIU has supplied evidence regarding actual costs. Lastly, the Commission believes that the AG and CUB's proposed disallowance does not take into account the effect of the merger when comparing test-year expense calculations, which is significant. The Commission finds that in this case, using an inflation based adjustment to AmerenIP's Account 920 through 923 amounts authorized in the last rate case is inappropriate and must be rejected.

D. Approved Operating Income/Revenue Requirement

Upon evaluating the effects of the determinations made above, the operating statements for AIU's respective service territories for electric and gas delivery services are approved as shown in the Appendices attached hereto.

VI. COST OF CAPITAL/RATE OF RETURN

A. Introduction

A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type of capital affects the overall or weighted average cost of capital, which is the rate of return a utility is authorized to earn on its net original cost rate base.

The Commission relies on the cost of capital standard to determine a fair rate of return. This cost, which can be determined from the overall rate of return or weighted average cost of capital, should produce sufficient earnings and cash flow when applied to the respective company‘s rate base at book value to: enable a company to maintain the financial integrity of its existing invested capital, maintain its creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable a company to continue to meet the needs of its customers.

These standards are effectively mandated by the landmark U.S. Supreme Court decisions Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944) ("Hope"). Meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holders and equity holder alike.

B. Capital Structure

1. Common Equity Balances

AIU accepted Staff witness Phipps‘ miscellaneous adjustments to AIU's common equity balances, including, removal of the unappropriated undistributed subsidiary earnings balance from each utilities‘ common equity balance, removal of Ameren Energy Resources Generating‘s Accumulated Other Comprehensive Income (―OCI") from AmerenCILCO‘s common equity balance, as well as removal of the preferred stock premiums from AmerenIP‘s common equity balance.

AIU's and Staff‘s agreed common equity balances for AmerenCILCO and AmerenCIPS are $217,459,214 and $506,691,386; each as of June 30, 2007. AmerenIP‘s agreed December 31, 2006 common equity balance equals

$1,076,124,965. The Commission finds these common equity balances appropriate and they will be adopted for this Order.

2. Preferred Stock Balances

Staff accepts AIU's proposed June 30, 2007 preferred stock balances for AmerenCILCO and AmerenCIPS. Staff and AIU agree on AmerenIP's December 31, 2006 preferred stock balance. Those agreed upon preferred stock balances are $36,450,067 for AmerenCILCO; $48,974,984 for AmerenCIPS; and $45,786,945 for AmerenIP. The Commission finds that these balances are appropriate and they will be adopted for this Order.

3. TFTN Balance-AmerenIP

Staff and AIU agree that AmerenIP's December 31, 2006 TFTN balance equals $171,533,494. The Commission finds this amount appropriate and will adopt it for this Order.

4. Short-Term Debt Balances

a. AIU's Position

AIU notes that Staff's position is that cash should not be netted against short-term debt to obtain the proper net short-term debt balance. Ms. Phipps argues that netting cash against short-term debt as part of the calculation of the proper amount of short-term debt ―si improper because cash is not a part of short-term indebtedness." AIU submits that the proper analysis is whether the capital structure accurately reflects the mix of debt supporting utility assets. AIU is of the opinion that the principal flaw with Staff's approach is that, by failing to net cash against short-term debt, Staff treats cash as a utility asset, serving utility purposes, but then does not include the cash in rate base. AIU submits that this produces a mismatch between the cost of funds supporting assets and the returns those assets earn.

AIU avers that it is holding relatively high cash balances due to AIU's credit standing in the aftermath of the legislative "crisis" involving the 2007 retail electric rate changes, and that AIU requires these cash balances for operating purposes. AIU notes that the cash balances sit in money market accounts, earning standard money market returns, to assure immediate access to the funds. AIU submits that were its credit position better, AIU would not hold cash balances at these levels, and that the utilities are holding these amounts of cash to satisfy their public utility service obligations. AIU claims it has lost same day access to funds and instead has had to rely on bank facility borrowings, which requires a three business day lead time and generally involves a minimum loan term of 30 days, and submits that this has had a considerable effect on the flexibility of managing cash.

AIU is of the opinion that there are two ways to treat the cash balances being held for utility purposes. One is to maintain them entirely outside of the ratemaking process by deducting them from the short-term debt balances, as AIU did. AIU submits that this produces a return on the cash (the money market interest rate) reasonably comparable to (although still less than) its cost (the short-term debt rate). A second alternative, in AIU's opinion, would be for the cash to be included in rate base, and the short-term debt be fully reflected in the capital structure. AIU avers that this approach could produce an excess return, however, because the cash would be earning both the overall cost of capital in rates, plus the money market return. AIU submits that it did not pursue this approach, because of this mismatch of cost and return.

AIU is of the opinion that Staff has elected a third method, which produces a significant mismatch between the cost of financing and the return on the assets being financed. AIU notes that Staff includes the full amount of short-term debt (other than money pool lendings and CWIP) in the utility capital structure, while simultaneously treating the cash as a non-utility asset. AIU submits that this treatment assumes that the cash is supported by a mix of capital equal to the proportion of capital supporting assets in rate base. AIU claims that this results in a conclusion that AIU would raise cash at a cost of roughly 8% and invest it in money market accounts earning roughly 3%. AIU submits that this is not a reasonable treatment proposed by Staff.

AIU argues that, by differentiating between (1) cash on hand funding loans to sister utilities and (2) cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios. AIU submits that in reality only a cash management decision differentiates the two, and in both instances, the cash is earning a return elsewhere, and the cost of capital supporting the cash should be consistent with the return.

AIU opines that this same reasoning is consistent with that used in discerning that short-term debt related to CWIP and loans to the money pool should not be included in the capital structure. AIU submits that the same short-term debt funds can not be used simultaneously to support rate base and fund CWIP or be loaned to sister utilities and that this is consistent with Staff's long-standing practice and Commission precedent.

AIU further argues that Ms. Phipps, in her calculation of the twelve-month average of short-term debt, improperly aligns the midpoint of the twelve months with the measurement date of the long-term capital structure components. AIU also submits that Ms. Phipps uses data that goes beyond this measurement date by up to six months. AIU opines that short-term debt balances are the result of costs during the test year/measurement period and that the use of measurement balances beyond this period results in a measurement mismatch between short-term debt and the other capital structure balances. AIU avers that Ms. Phipps must provide more compelling evidence that use of data within the boundaries of the test year/measurement period is not proper. Although the Commission ultimately sided with Staff and this approach in the most recent case, AIU submits that the language of the ruling was hardly a mandate.

While Staff argues that if a company's cost of capital is constant, short-term debt would not be used to finance cash, AIU submits that all of the components of the capital structure cost more than a company would earn on its cash investments. AIU posits that the cost of debt does not change just because the assets it supports earn a lower return, the cost of debt is set by the governing debt instrument.

AIU notes that while Staff suggests that cash is supported by low-cost equity capital, there is no suggestion where AIU is obtaining low-cost equity at a rate less than the short-term debt rate. AIU posits that Staff is tying cash to equity and only equity, while AIU avers that there is no way to isolate equity and apply it only to cash.

AIU opines that it has shown that the cash is being held for utility purposes, and if the cash is not netted against short-term debt to make it whole, then the cash should be included in rate base. While Staff argues that cash investments already earn a return commensurate with their risk, AIU suggests the problem is that the cash is not earning a return commensurate with its cost.

b. Staff's Position

Staff witness Phipps calculated the following short-term debt balances for the AIU: $82,500,351 for AmerenCILCO; $75,752,646 for AmerenCIPS; and $82,506,936 for AmerenIP; while AIU witness O'Bryan proposed the following short-term debt balances: $15,865,875 for AmerenCILCO; $11,902,241 for AmerenCIPS; and $47,106,782 for AmerenIP. Staff submits that AIU's calculations are flawed because Mr. O'Bryan: 1) used a measurement period that is not centered on the measurement date for long-term capital components, and 2) netted out all cash from short-term debt.

Staff notes that Ms. Phipps adjusted AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term debt measurement periods to have a midpoint that coincides with the measurement date for long-term capital structure components (i.e., June 30, 2007 for AmerenCILCO and AmerenCIPS; December 31, 2006 for AmerenIP), which she alleges better aligns the average balance of short-term debt with the long-term capital structure components. Ms. Phipps opines that the balances of short-term debt and long-term capital structure components can be perfectly aligned only if both are measured on the exact same dates, which would mean measuring the short-term and long-term capital structure component balances either on the same, single date, or as an average of the same 12-month period. She avers that the former has the disadvantage of not smoothing out the variation that often exists in short-term debt balances, while the latter has the disadvantage of being more time consuming and prone to measurement error due to the greater amount of data and calculations involved. Ms. Phipps submits that a reasonable, practical solution to those disadvantages is to measure the long-term capital components on a single date, while smoothing out the variation in short-term debt by using a 12-month average centered on the measurement date of the long-term capital structure components.

Staff notes that while Mr. O'Bryan argues that Staff's measurement period results in a measurement mismatch between balances of short-term debt and the other capital structure components, Mr. O'Bryan's argument is not pertinent in this case because there were no issuances, redemptions or maturities of equity or debt during those six months beyond AIU's long-term capital measurement dates, which would be included in Staff's measurement period but not AIU's.

Staff opines that a 12-month average centered on the measurement date of AIU's long-term capital structure components minimizes the total number of months that are misaligned. Staff submits that using its methodology, the total misalignment between long-term and short-term capital balances is 42 months, while using AIU's methodology results in a misalignment of 78 months. Staff argues that because the number of months of misalignment in AIU's calculation is greater than Staff's calculation, any measurement mismatch affects AIU's calculations more than it would Staff's.

Staff notes that the Commission adopted Staff's short-term debt balance calculations in Docket Nos. 99-0534, 01-0696, 03-0676/03-0677 (Cons.) and 06-0070/06-0071/06-0072 (Cons.). Staff also cites the Commission's Order in Docket No. 01-0696.

While Staff notes that Mr. O'Bryan argues that short-term debt balances are the result of costs during the test year/measurement period, Staff submits that Mr. O'Bryan's argument is based on the faulty premise that the terms —test year" and —measurement period" are synonymous. Staff notes that 83 Ill. Adm. Code 285.115 specifies that the capital structure measurement period refers to the period or point in time in which all long-term components of the capital structure are measured and may differ from the —test year." Staff further notes that AIU chose June 30, 2007 to measure the balances of long-term debt, preferred stock and common equity for AmerenCILCO and AmerenCIPS, which is six months after the end of the 2006 test year.

Staff submits that the Commission's Order in Docket No. 99-0534 distinguishes between the terms capital structure measurement period and test year when it states:

> . . . the cost of capital, and therefore its components, are not subject to the Commission's test year rules. In <u>Business and Professional People for the Public Interest et al. v. The Illinois Commerce Commission et al.</u>, 585 N.E.2d 1032,(December 16, 1991), the Supreme Court found, in part, that, "Because the post--in--service carrying charges are not operating expenses, they are not test—year items. Therefore, we agree with Edison and the Commission that recovery of deferred financing charges does not violate test--year principles." (<u>BPI II</u> at 1060) The implication of the Court's finding is that the balance of short-term debt, as a component of a utility's

authorized rate of return, is not subject to test--year rules. (Docket No. 99-0534, Order at 32-34 (July 11, 2000))

Staff argues that another flaw in Mr. O'Bryan's analysis is his subtraction of cash from each month-end gross short-term debt balance, which Ms. Phipps testified is improper because cash is not a part of short-term indebtedness. Staff's short-term debt calculation does not net out cash; however, it does reduce monthly gross short-term debt balances for each of the Companies by an amount equal to its month-end balance of bank loan contributions to the Ameren utility money pool.

Staff submits that while cash is fungible and can not generally be traced from source to use, nevertheless, a portion of AmerenCILCO's, AmerenCIPS' and AmerenIP's short-term balances appear to coincide with contributions to the Ameren utility money pool. Staff takes the position that in those instances where there is a clear, proximate connection between a company's short-term debt balance and its contributions to the utility money pool, it is appropriate to net money pool contributions out of gross short-term debt to avoid double counting bank loans from Ameren's credit facilities. Staff submits that this ensures that those contributions (which are included in the borrower's short-term debt balances) are not counted twice in both the lender and the borrower's capital structure.

Staff asserts that Mr. O'Bryan's reasoning is faulty in that it implies the cost of capital remains constant regardless of the riskiness of the assets it supports. Staff posits that the costs of the various sources of financing are a function of the riskiness of the assets being financed as well as the amount of debt used to finance the assets. Staff submits that Mr. O'Bryan's rationale suggests that holding the capital structure constant, a company's cost of capital would be the same whether its assets wholly comprised U.S. Treasury bills, electric distribution plant, or oil drilling equipment.

Staff posits that if this held true, companies would not have any cash on their balance sheet unless they also had short-term debt outstanding because it would perforce be financed with ―high cost" long-term debt and equity. Staff submits this is not true for AIU. Staff notes that during 2006, from January through November, AmerenCIPS' month-end short-term debt balances were zero; yet, during the same period, AmerenCIPS' month-end cash balances ranged from $0.5 million to $62.5 million. Staff further notes, on May 31, 2007, AmerenCIPS had no short-term debt outstanding and a $44 million cash balance.

Contrary to Mr. O'Bryan's opinion that AIU's capital must be tied to the assets included in rate base, Staff submits that the Commission has recognized that, for ratemaking purposes, a utility's capital structure is not required to equal rate base, but rather, a utility's capital structure must reflect the mix of capital a utility relies upon to finance its rate base. Specifically, in the prior CIPS and UE gas rates proceeding, the Commission's Order states:

> On a utility's financial statements, the total dollar value of assets must equal the total dollars of liabilities and owner's equity. In a rate case, however, the total dollars of jurisdictional rate base does not necessarily equal total capitalization . . . . Due to the fungible nature of capital, it is generally assumed that all assets, including assets in rate base, are financed in proportion to total capital . . . .
>
> The Commission has reviewed the parties' arguments and adopts Staff's proposal for calculating the amount of short-term debt included in UE's capital structure. (Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 65-68 (October 22, 2003))

Staff disputes the notion that AIU is holding relatively high cash balances due to its credit standing in the aftermath of the legislative crisis involving the 2007 retail electric rate changes, and submits that AIU held substantial cash balances prior to March 2007, which is when its issuer credit ratings were downgraded to below investment grade. Staff notes that on March 31, 2007, AmerenCILCO's cash balance equaled $200,000, and AmerenCIPS' cash balance equaled $47 million, while during 2006, AmerenCILCO held cash balances as high as $22 million and AmerenCIPS held cash balances as high as $63 million, excluding loans to utility affiliates through the money pool. Staff further notes that AIU has never identified specific months or amounts that relate solely to its credit rating downgrades, and when the risk of an electric rate rollback and freeze disappeared, AIU's short-term debt balances either increased or stayed approximately the same.

Staff notes that while AIU argues that cash must be netted out of short-term debt balances, Staff submits that AIU's own actions demonstrate otherwise. Staff notes that during August 2006, AmerenCILCO, AmerenCIPS and AmerenIP had net cash balances of $13 million, $77 million and $9 million, respectively. Staff further states that AmerenCIPS and AmerenIP paid common dividends totaling $40 million and $61 million, respectively, during 2007, rather than paying down short-term debt.

While AIU argues that failure to net cash against short-term debt implies that cash should be part of rate base, Staffs submits that cash does not need to be included in rate base because temporary cash investments already earn a return commensurate with their risk. Staff opines that including cash in rate base would increase the amount of the AIUs' rate base; and the rate base including cash would be relatively less risky than rate base excluding cash because there is virtually no risk associated with cash on hand. Staff submits that adding low risk cash to rate base assets would lower the cost of capital, which, combined with including the income on cash investments in the revenue requirement, would exactly offset the higher rate base.

Staff further notes that AIU takes the position that by differentiating between cash on hand funding loans to sister utilities and cash invested in liquid money market funds, Staff is suggesting that there is a fundamental difference between the two scenarios.

Staff submits however, that in reality only a cash management decision differentiates the two.

Staff opines that if AIU's proposed adjustment was for the purpose specified, then such adjustment would have been limited to the period during which AIU built up cash reserves and would have adjusted short-term debt for only the portion of cash AIU alleges it accumulated during that period. Staff notes however, that instead, AIU proposes to subtract the entire cash balance from short-term debt during the entire short-term debt measurement period. Staff notes that for AmerenCILCO and AmerenCIPS, the AIU proposed short-term debt measurement period covers June 30, 2006 to June 30, 2007, for which only four monthly balances out of thirteen occur after the March 2007 credit rating downgrade, and for AmerenIP, the AIU proposed short-term debt measurement period ends three months before the downgrades occurred. Staff avers that under no circumstances would it be reasonable to remove all cash, as AIU proposes to do, since on any given date a utility would likely have cash on hand for operating purposes.

Staff submits that the two alternatives that AIU has offered for the treatment of short-term debt balances have one thing in common, each would result in higher rates charged to ratepayers. Staff recommends that its suggested short-term balances be adopted for the purposes of this Order.

c. Commission Conclusion

AIU argues that it is holding abnormally high cash balances due to each utility's worsened credit situation following the 2007 retail electric rate changes, and suggests that these cash balances should be netted out from short-term debt balances to compute the capital structure for each company. AIU suggests that a second alternative would be to include the cash in rate base, and the short-term debt be fully reflected in the capital structure; however, AIU argues this might produce an excess return for each company as they would be earning a money market rate of return on the cash while also earning the approved return on equity.

Staff takes the position that the total amount of short-term debt should be reflected in the capital structure and that cash balances should not be netted out from the balances. Staff notes that cash is fungible and generally can not be traced from source to use, however it appears to Staff that a portion of each utilities' short-term debt balances coincide with contributions to the Ameren utility money pool. Staff suggests where there is a clear connection between the short-term debt and its contribution to the money pool, it is appropriate to net those contributions out of short-term debt to avoid double counting. Staff disputes that AIU is holding relatively high cash balances solely due to its credit standing, and notes several instances where one of the utilities held high cash balances prior to the retail electric rate crisis and the downgrade in each utilities credit rating.

The Proposed Order in this proceeding adopted AIU's proposed short-term debt balances rather than Staff's proposed balances. In its Brief on Exceptions, Staff maintains that cash balances should not be subtracted from short-term debt balances and that its proposed measurement period for short-term debt balances should be adopted rather than AIU's proposal. Staff, however, also provided several alternatives for the Commission's consideration in the event it rejected Staff's primary position. Specifically, using data presented in Staff Group Ex. 3, Staff presented information that would allow the Commission to combine Staff's measurement period for short-term debt balances with Staff's measurement proposal, with AIU's measurement proposal, and with a measurement approach that would remove only "excess" cash balances from the short-term debt balances.

As an initial matter, it appears from the record that neither the AIU proposal nor the Staff primary proposal is perfect and that each has raised valid concerns or criticisms of the other. All things considered, the Commission believes that Staff's suggested approach to remove excess cash from short-term debt balances, along with the adoption of Staff's measurement period, appears to be the approach best supported by record evidence. Upon consideration of all the evidence presented, the Commission finds that AIU has not justified subtracting the entire cash balance during the entire short-term debt measurement period. The Commission finds convincing Staff's argument that, in no event, should all cash be subtracted from the short-term debt balances. The record clearly indicates that AIU used short-term debt for purposes unrelated to the requirements that it hold unusually high balances. Thus, the suggestion of removing the "excess" cash is the most reasonable. Staff also suggests that it would be inappropriate, considering AIU's loss of same-day access to funds, to potentially enrich AIU through a higher authorized rate of return due to its affiliates' decision, which AIU disputes, to withhold financial support. While the Commission is always observant of such possible actions, as theorized by Staff, it does not appear that the record nor the arguments presented by the parties have been fully developed in this proceeding. In any event, the Commission notes that this issue was not a significant factor in the Commission's decision on the appropriate amount of short-term debt to include in the capital structure for AIU.

It appears to the Commission that, at least for a portion of Staff's short-term debt measurement period, AIU has been keeping higher than normal cash balances due to its relatively low credit rating, which resulted from the perceived electric rate crisis. The Commission agrees with Staff's assertion that in no event should all cash balances be subtracted from the short-term debt balances. As such, the Commission is of the opinion that adopting Staff's calculation of short-term debt, which removes "excess" cash is superior to AIU's proposal to remove all cash from short-term debt, and it is adopted for purposes of this docket.

The final issue with regard to short-term debt balances is whether the average balances of short-term debt should be centered upon the capital structure measurement date as Staff recommends, or should end at the same date as the capital structure measurement period as AIU recommends. The Commission notes that AIU's proposed short-term debt measurement period for AmerenIP ends three months before the March 2007 credit rating downgrades and, further, only a portion of AmerenCIPS' and AmerenCILCO's proposed measurement periods are after the credit downgrades. The Commission also notes that this issue is the same as that litigated in AIU's last rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)). The Commission has reviewed the record on this issue and again concludes that Staff's approach is superior to AIU's. The Commission notes that this issue is significant to the final calculation of the appropriate cost of equity. As illustrated by Staff's testimony, all else being equal, to use AIU's proposed measurement period in Staff's cost of capital recommendation, would cause the overall cost of capital to increase 54 basis points for AmerenCILCO, 20 points for AmerenCIPS, and 8 basis points for AmerenIP. The Commission also observes that in the South Beloit Water, Gas and Electric Company's rate case in Docket Nos. 03-0676/03-0677 (Cons.), the Commission adopted the approach advocated by Staff in this proceeding. The Commission will therefore adopt Staff's measurement period for calculating short-term debt balances in this proceeding. The conclusions reached in this portion of the order lead the Commission to adopt short-term debt balances of $72,643,527, $55,210,979, and $76,677,769 for AmerenCILCO, AmerenCIPS, and AmerenIP, respectively.

5. Long–Term Debt Balances

The Commission notes that Staff recommends the following long-term debt balances for AIU: $141,064,706 for AmerenCILCO; $446,741,385 for AmerenCIPS; and $709,096,036 for AmerenIP; while AIU proposes the following long-term debt balances: $141,064,013 for AmerenCILCO; $445,904,162 for AmerenCIPS; and $704,808,159 for AmerenIP. It appears to the Commission that despite the very minor differences between AIU and Staff, the resolution of this issue will be determined by the Commission decisions in the following parts of this Order; Embedded Cost of Long-Term Debt – AmerenIP, Embedded Cost of Long-Term Debt – AmerenCIPS, and Embedded Cost of Long-Term Debt – AmerenCILCO.

C. Cost of Debt

1. Short-Term Debt

AIU updated its cost of short-term debt to conform with Staff's calculations, and for purposes of this case, accepted Ms. Phipps‘ weighting methodology used to calculate the cost of short-term debt for AIU. This weighting methodology determined a spread over the London Inter-Bank Offer Rate index to calculate AIU's cost of short-term debt. The agreed upon costs of short-term debt are 4.04% for AmerenCILCO, 4.01% for AmerenCIPS, and 3.93% for AmerenIP.

IIEC witness Gorman recommended a reduction to AIU's cost of short-term debt. IIEC notes that AIU reduced its short-term cost to recognize more recent lower interest rates, and IIEC does not contest this issue further. The Commission finds the agreed costs of short-term debt for each company to be appropriate, and they will be adopted for the purposes of this Order.

2. Variable Rate Long-Term Debt

AIU accepted Ms. Phipps‘ interest rates for AmerenCILCO and AmerenCIPS Series 2004 auction rate pollution control bonds (―PCBs”). Ms. Phipps used interest rates from the last auctions prior to the December 2007 rating agency actions that affected the bond insurers that insured these PCBs. This, in turn, had a negative effect on the interest rates of the PCBs. AIU submits that although this is a reasonable approach to treat the cost of these bonds, this approach should not be used with respect to the AmerenIP auction rate PCBs. The agreed upon interest rates are 4.10% for AmerenCILCO‘s $19.2 million auction rate PCBs and 4.25% for AmerenCIPS‘ $35 million auction rate PCBs. The Commission finds these rates to be appropriate, and they will be adopted for the purposes of this Order.

3. Embedded Cost of Long-Term Debt for AmerenCILCO

For AmerenCILCO, Staff witness Phipps calculated a 6.65% embedded cost of long-term debt while AIU calculated a 6.67% embedded cost of long-term debt. The difference between those calculations relates to the annualized interest expense for AmerenCILCO‘s auction rate PCBs. AIU accepted Staff‘s proposed 4.10% rate for AmerenCILCO‘s auction rate PCBs, but Staff notes that AIU failed to update its long-term debt schedule to reflect Staff‘s proposal. As such, Staff believes the Commission should adopt Staff‘s calculation of AmerenCILCO‘s embedded cost of long-term debt, as presented in Staff Ex. 4.0R, Sch. 4.03 CILCO. AIU indicates it does not contest Staff‘s long-term debt rate for AmerenCILCO. The Commission finds Staff's suggested embedded cost of long-term debt for AmerenCILCO to be appropriate and it will be adopted for the purposes of this Order. The Commission understands that as a result, the proper balance of long-term debt to be adopted for AmerenCILCO is $141,064,706, as Staff recommends.

4. Cost of AmerenIP's Transitional Funding Trust Notes

a. AIU's Position

AIU witness O‘Bryan employed an internal rate of return (―IRR”) method to determine the embedded cost of the AmerenIP TFTN. AIU opines that the IRR method is appropriate for determining the cost of this debt because AmerenIP does not have economic use of the entire amount of net proceeds of the TFTN between the issuance date (December 1998) and the final maturity date (December 2008). AIU submits that the use of the IRR method to determine the cost of TFTNs was approved by the Commission in the 1999 and 2001 electric delivery services tariff cases as well as the 2004 gas rate case.

AIU argues that Staff witness Phipps incorrectly suggests that the TFTN coupon rate should not be calculated using an IRR monthly compounded methodology. AIU submits that Ms. Phipps' argument to annualize the monthly discount rate by multiplying the rate by twelve is based on the faulty assumption that the Instrument Funding Charges ("IFC") collections are remitted by AmerenIP to the indenture trustee on a monthly basis, which is not true in this case. AIU claims that AmerenIP remits funds to the trustee on a daily basis, and those funds are unavailable to the company once remitted. AIU is of the opinion that Ms. Phipps' means of calculating the TFTN cost understates the true cost to AmerenIP.

AIU also notes that while Ms. Phipps claims that Mr. O'Bryan incorrectly included an additional year of cash flows in the IRR analysis, AIU opines that these cash flows must be included in the IRR analysis, as they make up the test year cost calculations. AIU notes that unlike the balance of TFTNs, which is a capital structure component and must be measured as of the end of the test year, the IRR calculates the true cost of the TFTNs and must incorporate the full test year cash flows. AIU further notes that while Ms. Phipps adjusted the amount of —Net Proceeds Used to Retire Principal" to reflect a $100,000 subtraction to the capital subaccount, stating that Mr. O'Bryan did not include this in his calculations. However, according to AIU, Mr. O'Bryan did include this subtraction in the last line of the —Collection Amount" column in the IRR spreadsheet, and AIU submits that this amount is embedded in his IRR calculation.

b. Staff's Position

Staff witness Phipps calculated that AmerenIP's embedded cost of TFTNs equals 4.92%. Ms. Phipps then made three adjustments, which reduced the TFTN IRR to 4.5% in comparison to AmerenIP's 5.6% IRR calculation.

Ms. Phipps adjusted the IRR analysis to begin on AmerenIP's proposed December 31, 2006 capital structure measurement date, as Staff submits that AIU's analysis incorrectly includes one additional year of cash flows because the IRR calculation begins January 1, 2006. Staff opines that calculating the cost of the TFTNs using data beginning January 1, 2006 overstates the cost of debt due to the twelve months of additional cash flows that represent the present value of the TFTN collection amounts during 2006. Staff notes that adjusting the IRR analysis by changing the measurement period to include one additional year of cash flows increases the IRR by approximately one percentage point (1.0%), and increases AmerenIP's overall cost of capital by approximately 8 basis points.

Staff submits that it is appropriate to calculate the TFTN cost as of the capital structure measurement date and that to include the 2006 cash flows in the TFTN IRR analysis would be incorrect. Staff notes that AIU chose the higher January 1, 2006 IRR (i.e., approximately 5.6%) rather than the lower December 31, 2006 IRR (i.e., approximately 4.5%) and combined it with the lower December 31, 2006 balance of TFTNs ($172,800,000) rather than the higher January 1, 2006 balance of TFTNs ($259,200,000). Staff submits that AIU's IRR calculation violates the present value principle on which it rests: the value of an asset equals the cumulative value of its future discounted cash flows.

Staff further adjusted the TFTN IRR analysis by increasing the amount of —Net Proceeds Used to Retire Principal" by $100,000 as the TFTN prospectus indicated the Trust retained $4,220,000 of TFTN sale proceeds in the capital subaccount rather than the $4,320,000 amount AIU's calculation assumes. Staff avers that although Mr. O'Bryan correctly modeled that $4,220,000 from the capital subaccount will be returned to AmerenIP in December 2008, he incorrectly modeled that $4,320,000 of the TFTN proceeds were deposited in the Capital Subaccount in December 1998. Staff submits that failing to make this adjustment results in an artificially low amount of cash available to retire the TFTNs, thereby inflating the results of the TFTN IRR analysis.

Staff notes the TFTN coupon rate is calculated using an analysis that finds the monthly discount rate that equates the cumulative present value of the monthly cash servicing costs of the TFTNs to the principal outstanding net of over-collateralization. Staff submits that while AmerenIP calculated an annual discount rate that reflects monthly compounding, Staff calculated the monthly discount rate and multiplied it by twelve to annualize it.

Staff opines that while annualizing a periodic rate of return by compounding it to the power equal to the number of periods in a year is necessary for determining the required rate of return from the perspective of investors, the cost of TFTNs is embedded; that is, the cost of TFTNs is calculated from the perspective of the utility, not investors. Staff submits that embedded costs are annualized by multiplying the periodic rate by the number of periods in a year.

While AIU argues that annualizing the monthly discount rate used in the IRR calculation, rather than compounding it, understates the true cost to the utility because AmerenIP remits funds to the TFTN trustee on a daily basis, Staff avers that AIU's monthly compounding in the IRR calculation overstates the embedded cost of TFTNs and should be rejected. Staff submits that the payment timing difference of TFTNs is more properly accounted for using a working capital adjustment than a cost of capital adjustment. Staff's proposed working capital allowance for AmerenIP includes this adjustment to reflect the timing difference between AmerenIP's TFTNs and its other long-term indebtedness, which AIU witness Adams testified was appropriate.

Staff notes that in AmerenIP's prior electric delivery service rate case (Docket Nos. 06-0070/06-0071/06-0072 (Cons.)), Staff's proposed working capital allowance included a 91.5-day lead for conventional debt and a two-day lead for TFTNs, which was accepted by the Commission. Staff submits that its proposed treatment of the AmerenIP TFTN notes is appropriate, and AIU's suggestion that the IRR calculation requires monthly compounding should be rejected.

Staff notes that while AIU takes the position that its method of calculating the IRR to determine the cost of TFTN was approved by the Commission in the 1999 and 2001 electric DST cases as well as the 2004 gas case, Staff submits that the Orders for AmerenIP‘s 2001 DST case and 2004 gas case do not describe the TFTN cost calculation and can not be relied upon to support AmerenIP‘s IRR methodology as Staff and IP stipulated to an overall cost of capital, including a TFTN cost rate. Staff further notes that in IP‘s 1999 DST case, Staff and IP agreed upon the TFTN cost rate, but the Order does not describe the TFTN cost calculation.

Staff opines that the use of IRR analysis to calculate the TFTN cost was not contested in the previous case (i.e., Docket Nos. 06-0070/0071/0072 (Cons.)) and is not contested in the instant case. Staff notes that in both cases, Staff and AmerenIP calculate the TFTN cost rate using IRR analysis. In both cases, to calculate the annual IRR, Staff multiplies the monthly IRR by 12, while in contrast, AmerenIP compounds the monthly IRR. Staff further avers that in the 2006 IP DST case, the Commission concluded that Staff‘s method for calculating the embedded cost of TFTNs was correct.

c. Commission Conclusion

The Commission notes that this issue appears to be the same as was litigated in AIU's last DST case. The Commission has reviewed the record on this issue and again concludes that Staff‘s method for calculating the embedded cost of TFTNs is correct. The cost of long-term debt, including TFTNs, is known with relative certainty and should be calculated on an annual basis. Multiplying the stated monthly rate by 12 produces an annualized embedded cost that is consistent with the entire test year revenue requirement calculation. Additionally, AIU's concern about the economic impact of frequent remittance by AmerenIP to the trustee is recognized in the CWC allowance adopted in this Order. The Commission finds that Staff‘s method for calculating the interest rate for AmerenIP‘s TFTNs when combined with the appropriate CWC calculation properly reflects AmerenIP‘s cost of providing service. The Commission finds Staff's estimate of AmerenIP's embedded cost of TFTNs, 4.92%, to be reasonable for purposes of setting rates in this proceeding.

5. AmerenIP's Embedded Cost of Long-Term Debt

a. AIU's Position

AIU witness O‘Bryan updated AmerenIP‘s long-term debt schedule to reflect the recent refinancing of its auction rate PCBs. AIU notes that on April 8, 2008, AmerenIP issued $337 million of senior secured notes for the purpose of redeeming AmerenIP‘s outstanding PCBs that were in auction rate mode. AIU submits that the parties agree that negative credit rating actions against the bond insurers starting in December 2007 caused rates to spike in the auction rate market. AIU notes that rates on these securities, which were in the range of 1.54% - 3.93% over the period 2004-2007, saw rates climb to as high as 18%. Due to the extremely high rates on these securities recently, AIU states that Ms. Phipps measured these rates using the interest rates from the last auctions prior to the December 2007 rating actions by Moody's Investors Service ("Moody‘s") and S&P on the companies that insure the AIU's auction rate PCBs.

Ms. Phipps reasoned in direct testimony that one possible outcome was the refinancing of these securities due to the recent authority the Commission granted AmerenIP to do so. AIU notes that AmerenIP did refinance these securities, and as result, AIU submits that Ms. Phipps' proxy rates should be updated for actual rates that reflect AmerenIP‘s true amount and cost of long-term debt for the foreseeable future.

AIU submits that this updating of AmerenIP‘s long-term debt schedule to reflect the refinancing of its auction rate PCBs should not be considered a selective update, and notes that Ms. Phipps contemplated such a scenario in her direct testimony. AIU avers that the rates that she used were a proxy for the true rate on the PCBs and should be considered a short-term substitute until a more permanent rate can be used which would reflect the truer cost of the capital. AIU submits that that rate is now available, and given this special situation should be viewed as more appropriate than Ms. Phipps‘ proxy rate.

AIU's suggests that its proposed replacement of a proxy that Staff developed in light of market turmoil, with the cost of the now-known permanent replacement is appropriate and should not be considered by the Commission to be a selective update.

b. Staff Position

Staff submits that as of December 31, 2006, AmerenIP‘s balance of long-term debt equals $709,096,036, and the embedded cost of long-term debt equals 7.34%.

AmerenCIPS, AmerenCILCO and AmerenIP each have outstanding variable rate long-term indebtedness in the form of PCBs with interest rates established every 7 or 35 days through an auction (the —auction rate PCBs”). The parties agree that during December 2007, Moody‘s placed the credit ratings of the companies that insure those auction rate PCBs on review for possible downgrade and S&P assigned the ratings of those bond insurance companies to Negative CreditWatch or assigned their ratings negative Outlooks, and that those negative credit rating actions preceded a dramatic increase in the interest rates for the auction rate PCBs.

In her direct testimony, Ms. Phipps stated that during the period rates set in this proceeding are in effect, one of two events is likely to occur: 1) the market for insured tax-exempt bonds will return to a more stable equilibrium in which interest rates on such indebtedness reflect the risks of default, or 2) AIU will refinance the auction rate PCBs. Ms. Phipps testified that the results of the last auctions available at the time she filed direct testimony were not reasonable estimates of the rates AIU will incur on the associated indebtedness in either of those events. Ms. Phipps indicates she estimated the cost of the auction rate PCBs using the interest rates from the last auctions prior to the December 2007 rating actions by Moody‘s and S&P on the companies that insure AIU's auction rate PCBs.

Specifically, Ms. Phipps recommends using the following interest rates for AmerenIP‘s auction rate PCBs: 4.865% for AmerenIP‘s $150 million auction rate PCBs;

4.571% for AmerenIP's $111.77 million auction rate PCBs and 5.857% for AmerenIP's $75 million auction rate PCBs. Staff notes that AIU accepted Staff's cost estimates for AmerenCILCO's and AmerenCIPS' auction rate PCBs, which Staff says were derived in the same manner as Staff's cost estimate for AmerenIP's auction rate PCBs, however AIU did not accept Staff's interest rate for AmerenIP's auction rate PCBs.

Staff submits that AIU proposes a selective update to AmerenIP's long-term debt schedule to reflect the April 2008 refinancing of AmerenIP's auction rate PCBs by removing $336.77 million auction rate PCBs, including $337 million of 6.25% Senior Secured Notes, and reflecting March 31, 2008 balances of unamortized loss for the reacquired PCBs only, which is fifteen months beyond the December 31, 2006 balances for every other long-term debt issue. Staff submits that this selective update effectively increases the embedded cost of the PCB-related indebtedness by approximately two percentage points (from 4.6% to 6.5%) and increases the embedded cost of debt for AmerenIP from 7.14% to 7.98%. Staff opines that AIU's selective update to AmerenIP's long-term debt schedule provides neither an accurate nor complete view of AmerenIP's cost of capital on either December 31, 2006, or during April 2008.

Staff recommends against allowing selective updates to AmerenIP's cost of capital. Should the Commission determine it would be appropriate to update IP's cost of capital to reflect the 6.25% interest rate Senior Secured Notes AmerenIP issued to redeem its auction rate PCBs, Staff recommends the Commission also update the costs of variable rate debt issues (short and long-term) and the cost of common equity, leaving the capital structure balances unchanged. Further, since AmerenCILCO and AmerenCIPS also refinanced PCBs during April 2008, Staff submits that their variable rate debt and common equity costs should be updated as well.

Ms. Phipps testified that the updated cost of short-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 3.95%, 3.92% and 3.74%, respectively, and the updated cost of long-term debt for AmerenCILCO, AmerenCIPS and AmerenIP are 6.63%, 6.24% and 7.94%, respectively. Staff submits that for AmerenCILCO and AmerenCIPS, the updated interest rate for auction rate PCBs equal their respective updated short-term debt cost, while for AmerenIP, the updated interest rate for auction rate PCBs equals 6.25%, which is the interest rate for the Senior Secured Notes that AmerenIP issued in April 2008 to replace auction rate PCBs.

Should the Commission determine it is necessary to update the AIU's cost of capital estimates due to recent financing activity in connection with redeeming and refinancing auction rate PCBs, then Staff submits that the cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's gas delivery services operations would be 7.94%, 8.14%, and 8.90%, respectively. Those cost of capital recommendations reflect Staff witness Freetly's updated 10.73% cost of equity estimate for the utilities' gas delivery services operations. Staff asserts that the updated cost of capital for AmerenCILCO's, AmerenCIPS' and AmerenIP's electric delivery services operations would be 7.75%, 7.94%, and 8.69%, respectively. Those cost of capital recommendations reflect Ms. Freetly's updated 10.32% cost of equity estimate for the utilities' electric delivery services.

Staff states that in AIU's 2006 electric delivery services rate case, the Commission noted the risks inherent in selective updates to capital structure components, rejected AIU's proposed selective updates to interest rates, and endorsed measuring all the costs of capital at or over the same period. Staff opines that AIU's attempted change in the auction rate PCB's also changes costs and balances included in AmerenIP's embedded cost of long-term debt and ignores AmerenIP's other recent financing activity and changes to other capital structure costs and balances that occurred between December 31, 2006 and April 2008. Staff avers that until the conclusion of AmerenIP's next rate case, Staff's proposed cost of debt will be more than sufficient to cover the additional interest expense AmerenIP incurs on its new bonds relative to the interest expense of its auction rate PCBs.

Staff recommends its calculation of AmerenIP's embedded cost of long-term debt be adopted and AIU's selective update should be rejected. Should however, the Commission adopt AIU's calculation of the embedded cost of long-term debt, Staff submits that the Commission should adopt Staff's alternative cost of capital recommendations for AmerenCILCO, AmerenCIPS and AmerenIP. Despite the flaws inherent in Staff's alternative recommendations for AIU, Staff insists they are superior estimates of the cost of capital in comparison to AIU's selective update to AmerenIP's long-term debt schedule because they provide a more complete and more accurate view of AIU's cost of capital.

c. Commission Conclusion

The Commission notes that it has generally endorsed the principal of measuring all of the costs of capital at or over the same period. The Commission is of the opinion that such an approach generally contributes to a test year revenue requirement that matches the cost of providing services and, in the Commission's view, is fair to both consumers and the utility investors. As the Commission noted in AIU's last delivery services case:

> The Commission becomes wary when a party proposes updates to certain components of the cost of capital without providing updates to all components. Allowing selective updates could serve to encourage utilities to only provide updates if the cost of components increased. Absent sufficient justification, this would be unfair to ratepayers… (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 109)

The parties are in agreement that an outside event affected the credit markets, and resulted in interest rates on auction rate PCBs that were far higher than the interest rates typically associated with those PCBs. It appears to the Commission that both parties have presented an adjustment to the actual interest rate incurred in the December, 2007 auction of AmerenIP PCBs, one prospective and one retrospective, and the question presented is whose update is more appropriate. The Commission is concerned that AIU's proposed use of the actual results from the April 8, 2008 refinancing does not take into consideration other relevant changes to AIU's cost of capital components and might be considered a selective update. The fact that Staff, in the event the Commission adopts an update to AmerenIP's PCB cost, recommends multiple other changes to components of cost of capital, verifies that the selective update concern is warranted.

Given that the cost of capital changes constantly, the Commission is reluctant to start down a path of selective updates or continuous updates during the pendency of a rate case. The Commission further notes that AIU has accepted Staff's proposed method for calculating the interest rates associated with AmerenCIPS' and AmerenCILCO's PCBs. Staff indicates it made those calculations in a similar manner to Staff's proposal for AmerenIP and that AmerenCIPS and AmerenCILCO also refinanced the auction rate PCBs in April 2008. The Commission is concerned that AIU fails to explain why the AmerenIP PCBs should be treated differently than the AmerenCIPS and AmerenCILCO PCBs.

Thus, the Commission finds that AIU's proposal to update the cost of AmerenIP's PCBs should be rejected. For purposes of this proceeding, the Commission finds Staff's original estimate of AmerenIP's embedded cost of debt, 7.34%, and its proposed balance of long-term debt, $709,096,036, to be reasonable for purposes of setting rates in this proceeding.

6. AmerenCIPS' Embedded Cost of Long-Term Debt

The parties are in disagreement over Staff's recommended cost of AmerenCIPS' long-term debt, wherein Staff removed the incremental cost of AmerenCIPS' June 14, 2006 bonds. The parties are in agreement that in May 2005, AmerenUE transferred its Illinois utility assets to AmerenCIPS in exchange for a $67 million, five-year promissory note bearing a 4.7% interest rate. They also agree that on June 14, 2006, AmerenCIPS issued $61.5 million, 30-year bonds with a 6.7% interest rate, using the proceeds from that debt issuance to pre-pay the intercompany note held by AmerenUE. AIU had calculated a long-term debt cost for AmerenCIPS of 6.67%, whereas Staff calculates a long-term debt cost of 6.27% after removing the incremental cost of the June 14, 2006 refinancing.

The Commission notes that all parties agree with the general financial principle that as interest rates rise, the market value of outstanding fixed-interest rate debt falls such that the yield on that debt is competitive with that on new debt that pays interest at the new, higher interest rates. Both parties further agree that this is true due to the fact that the future stream of cash flows, both interest and principal, is less valuable when interest rates rise because the interest rate on the note is fixed.

a. AIU's Position

AIU submits that Ms. Phipps improperly removed from AmerenCIPS‘ embedded cost of long-term debt the incremental cost due to its decision to refinance the 4.70% intercompany note with 6.7% bonds. AIU takes the position that AmerenCIPS was justified in refinancing the 4.70% note, noting that the refinancing extended the date of final maturity from 2010 to 2036, while the original 4.70% note had a remaining life of just over three years. AIU submits that this extension reduced AmerenCIPS‘ refinancing risk and that the more permanent capital achieved by extending the term corresponded with the permanent T&D assets which it financed. In addition, AIU avers that the new structure relieved AmerenCIPS from having to fund annual amortization payments, and that the principal payments that remained at the time the note was refinanced were $5.6 million in May 2007, $5.9 million in May 2008, and $6.2 million in May 2009, which would have been made in addition to quarterly interest payments. AIU notes that the 6.70% bond has a non-amortizing bullet structure with full principal paid at maturity, pays interest semi-annually, and affords AmerenCIPS valuable flexibility through the extension of maturity and freedom from the burden of annual amortization payments.

While AIU agrees that an inverse relationship exists between interest rates and bonds prices, and that the value of a note or loan to the lender falls whenever interest rates rise, AIU submits that this principle is not relevant to a lender or an initial investor at loan origination. Further, early redemption terms are set at the note‘s inception and are typically not negotiated during the life of the loan, with the possible exception being a distress/bankruptcy situation.

AIU notes that the AmerenCIPS intercompany note states in part:

> . . . AmerenCIPS (the —Maker”), promises to pay to the order of Union Electric Company d/b/a AmerenUE (the —Payee”)…the principal amount of $66,695,406…Upon receiving the prior written consent of the Payee, the Maker shall have the right to prepay the principal amount of this Note, in whole or in part, without premium or penalty. All partial prepayments shall be applied first to accrued interest under this Note and then to principal installments . . . . (AIU Initial Brief at 251)

AIU submits that the above excerpt states clearly the principal amount to be paid, and that any prepayment is without premium or penalty. AIU claims that there is no mention of a discount nor anything that can be construed as an ongoing negotiation between the parties regarding the amount ultimately owed.

AIU avers that Staff fails to distinguish the difference between the primary loan/bond market and the secondary market. AIU agrees that in an environment of increasing interest rates, the value of the AmerenCIPS note would decline, and were AmerenUE (the lender or investor) to attempt to sell the note to a third party in the secondary market, it would likely have had to accept a price below par to do so. AIU submits that AmerenCIPS, as obligor, was bound by the contractual terms of the note that requires the payment of the full principal amount of the loan at or before maturity.

AIU notes that Staff argues that AmerenCIPS extended a benefit to AmerenUE by retiring a promissory note before its due date and that reflecting the full cost of the replacement note would violate Section 9-230 of the Act by increasing AmerenCIPS' cost of capital due to its affiliation with AmerenUE. Staff takes the position that when AmerenCIPS paid AmerenUE the entire balance to retire the note, it gave AmerenUE an unnecessary benefit and the resulting refinancing is unreasonable.

AIU submits however, that AmerenUE is not in the regular business of lending or financing third parties, but is instead a public utility in Missouri and was the lender here only because AmerenCIPS signed a promissory note when it acquired AmerenUE's Metro East properties. AIU contends that, unlike an institutional lender, AmerenUE would not be expected to take the money from the early retirement of the note and return to the debt markets to lend the money to another party at higher interest rates. AIU submits that there was no evidence that AmerenUE was dissatisfied with the interest rate under the note or that AmerenUE would have been willing to accept a discount to the principal for early payment. AIU posits that unlike the case of an institutional lender, there is no obvious opportunity cost to AmerenUE from remaining a party to the note. AIU submits that Staff's theory is inapplicable here, there is no violation of Section 9-230, and Staff's adjustment should be rejected.

b. Staff's Position

Staff witness Phipps calculated a 6.27% embedded cost of long-term debt for AmerenCIPS, while AIU proposed a 6.67% embedded cost of long-term debt for AmerenCIPS. Staff submits that the difference in those calculations results from Staff's adjustment to remove from AmerenCIPS' embedded cost of long-term debt the incremental cost due to AmerenCIPS' decision to refinance a 4.70% intercompany note with 6.7% senior secured notes. Staff avers that this adjustment is required by Section 9-230 of the Act, which 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 nonutility companies.

To assess whether interest rates had changed from the date the note was issued until one year later when AIU issued long-term bonds to replace the intercompany note, Ms. Phipps examined the 4.7% interest rates on the note in comparison to the implied interest rate for bonds with similar risk and terms to maturity. Ms. Phipps testified that on May 5, 2006, concurrent interest rates for 3-year and 5-year BBB+/Baa1 bonds indicate the implied yield on 4-year BBB+/Baa1 bonds equaled approximately 5.7% versus 4.7% on May 2, 2005, the date when AmerenCIPS issued the intercompany note. Staff further notes that although interest rates on 4-year bonds had risen since May 2005, AmerenCIPS did not receive any discount on the repurchase price of the promissory note. Staff asserts that due to this increase in interest rates, AmerenCIPS should have received a discount on the repurchase of the promissory note.

Relying on Section 9-230 of the Act, Staff removed from AmerenCIPS' embedded cost of long-term debt any incremental cost increase due to its decision to refinance the 4.7% intercompany note with 6.7% bonds because the loan agreement between AmerenCIPS and AmerenUE did not oblige AmerenCIPS to retire the promissory note at face value on the demand of AmerenUE, and in a transaction with an unaffiliated counterparty without such a provision, the borrowing entity would be able to redeem its indebtedness at a discount to face value.

Staff argues that because the value of a loan to the investor (i.e., lender) falls below face value whenever interest rates rise on loans with similar terms and risks. Staff says that in an arms length transaction, a borrower would not have to pay full principal amount to prepay a loan carrying a below market interest rate unless the original loan agreement required the borrower to do so. Staff submits that ―make whole" provisions are designed to protect lenders' gains in market value in the event the borrower wants to refinance its debt should interest rates fall by requiring borrowers who want to refinance debt that bears above-market interest rates to pay in excess of the principal amount, not to protect their losses in market value whenever interest rates rise. Staff posits that the intercompany note did not include such a provision, and therefore, AmerenUE's principal amount was not protected from such a loss and it should not be granted after-the-fact.

Staff argues that AmerenCIPS' alleged inability to pay less than principal amount for below market rate debt is inconsistent with AmerenIP's experience. Staff notes that during January 2000, when long-term Baa-rated utility bond yields had risen to 8.40%, AmerenIP redeemed $32 million of its 7.50% first mortgage bonds maturing in 2025. Staff notes that AmerenIP's long-term debt schedule shows a gain was realized on that redemption due to higher long-term interest rates on the redemption date vis-à-vis the interest rate on the bonds.

To remove any incremental cost increase due to the refinancing, Ms. Phipps proposes two adjustments. First, she proposes dividing the balance of the 6.7% debt issuance in two components, with a 4.7% interest rate applied to the first component, which was the portion of the intercompany note that would have been outstanding as of June 30, 2007 had AmerenCIPS not retired it before maturity (i.e., $55,688,092). She then applies a 6.7% interest rate to the second component, which was the balance of the $61.5 million bonds (i.e., $5,811,908, which equals $61,500,000 less $55,688,092). She then proposes reducing the unamortized balances of debt discount and expense for the 6.7% bonds in proportion to the principal amount of those bonds that she included in AmerenCIPS' embedded cost of long-term debt. Next, she calculated the annual amortization expense for debt discount and expense relative to the prorated unamortized balance using straight-line amortization.

Staff notes that AIU opposes Staff's adjustment to remove the incremental increase in AmerenCIPS' cost of capital due to its intercompany note with AmerenUE and argues the refinancing benefited AmerenCIPS by extending the maturity from 2010 to 2036 and eliminating the obligation to fund $6 million annual amortization payments. Staff submits that AIU exaggerates the amount of flexibility gained by refinancing the intercompany note with bonds. Staff notes that not only did the original note include a provision that would allow AmerenCIPS and AmerenUE to extend the maturity of the note another five years by mutual agreement, but further, the note was subordinated to all other of AmerenCIPS' indebtedness. Staff avers that any benefits AmerenCIPS attributes to refinancing the note would have been benefits at the time of the asset transfer which originated the note. Staff submits that neither of AIU's arguments relating to the perceived benefits associated with refinancing the intercompany note are compelling.

Staff further suggests that neither of the arguments relating to the perceived benefits associated with refinancing the note are relevant. Staff insists that Section 9-230 of the Act does not allow the Commission to consider what portion of a utility's increased cost of capital caused by an affiliation is reasonable and therefore should be borne by ratepayers. According to Staff, the Second District Appellate Court in 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 ―if a utility's exposure to risk is one iota greater, or if it pays one dollar more for capital because of its affiliation with an unregulated or nonutility company, the Commission must take steps to ensure that such increases do not enter in its [rate of return] calculation."

Staff submits that consistent with Section 9-230 of the Act, it would be illegal to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. Staff notes that AIU does not dispute that the refinancing increased AmerenCIPS' cost of capital, and Section 9-230 of the Act prohibits including in AmerenCIPS' cost of capital any increase that is the direct or indirect result of AmerenCIPS' affiliation with unregulated or non-utility companies.

While AIU suggests that the benefits justified refinancing AmerenCIPS' intercompany note from AmerenUE, Staff avers that it has never argued that AmerenCIPS should not have refinanced the note and Staff takes no position on that decision. Rather, Staff takes the position that AmerenCIPS paid an above-market cost to refinance the note.

While AIU claims that in the market, AmerenCIPS would never be able to prepay a note for less than the principal amount, Staff submits that this note did not contain language requiring redemption of the note for no less than the principal amount upon demand by AmerenUE. Staff avers that the note at issue in the instant proceeding makes redemption optional, and that under those circumstances, the borrower, in this case AmerenCIPS, should not redeem a note that carries a below-market interest rate by repaying 100% principal unless the note required the borrower do so.

While AIU argues that because the note was privately held, AmerenCIPS could not redeem it at a market rate below face value, Staff notes that AmerenCIPS chose to enter into a private loan agreement with an affiliate. Staff submits that had AmerenCIPS gone to the market to raise funds, rather than borrow from an affiliate, AmerenCIPS would have had the opportunity to repurchase outstanding, below-market rate indebtedness for less than face value. Staff posits that for ratemaking purposes, the Commission must treat the intercompany note as if it had been held by an unaffiliated party, and under this circumstance, AmerenCIPS would have had the opportunity to repurchase that indebtedness at market rates rather than face value.

Staff submits that its calculation of AmerenCIPS' embedded cost of long-term debt, which is consistent with the requirements of Section 9-230 of the Act, should be adopted and AIU's cost calculation should be rejected.

c. Commission Conclusion

The Commission notes that Staff is rightly concerned about the possibility of cross-affiliate subsidization and the possibility that AmerenCIPS' ratepayers are providing a windfall to AmerenUE by the redemption at issue here. The parties are in agreement that interest rates had risen since the note in question was issued. Staff argues that if AmerenCIPS made the business decision to refinance this note, it should have been able to redeem them for less than face value due to the interest rate environment. AmerenCIPS submits that this situation does not apply to bonds or notes unless they are in the secondary market, and suggests that ratepayers are benefitting by the restructuring of this debt as AmerenCIPS makes interest-only payments, and the term of this debt is now extended.

The Commission finds that while there may be some collateral benefits to AmerenCIPS' ratepayers, it appears that there is an increased cost due to this transaction, and pursuant to 9-230 of the Act, it would be improper to reflect any resulting incremental cost increase in AmerenCIPS' cost of capital, regardless of any potential benefits relating to repayment flexibility that AmerenCIPS may realize due to refinancing the intercompany note with bonds. The Commission finds that for purposes of this proceeding, Staff's calculation of AmerenCIPS' embedded cost of long-term debt, 6.27%, and its balance of long-term debt, $446,741,385, are reasonable and they are hereby approved.

D. Cost of Preferred Stock

Staff and AIU agree that the embedded cost of preferred stock for AmerenCILCO, AmerenCIPS and AmerenIP equals 5.34%, 5.13% and 5.01%, respectively. The Commission finds these embedded costs of preferred stock to be appropriate, and they will be adopted for the purposes of this Order.

E. Cost of Common Equity

1. Overview

a. Staff's Position

Staff witness Freetly estimates the investor-required rate of return on common equity to be 10.72% for the natural gas distribution operations and 10.68% for the electric delivery service operations of AIU. Ms. Freetly measured the investor-required rate of return on common equity with the discounted cash flow (“DCF”) and Capital Asset Pricing Model (“CAPM”) analyses. For the AIU gas utilities, she applied those models to a sample of gas distribution companies. For the AIU electric utilities, she applied those models to a sample of regulated electric utilities that are assigned industry classification codes of 4911 (electric services) or 4931 (electric and other services combined) within S&P‘s Utility Compustat. Specifically, she applied them to those utilities that have neither pending nor recently completed significant mergers, acquisitions or divestures; that have a long-term growth rate from Zacks Investment Research (“Zacks”); and whose beta was not affected by significant events. Ms. Freetly did not include Ameren Corporation in her Electric sample due to the proximity of an 18% decline in Ameren‘s stock price to a conference call during which Ameren management discussed the pending Illinois rate cases.

Staff notes that in order to determine the suitability of her cost of equity estimates for AIU's gas and electric utility operations, Ms. Freetly assessed the risk level of her gas and electric samples relative to that of each of the Illinois utilities. She calculated the funds from operations (“FFO”) to interest coverage ratios and FFO to total debt ratios for the gas and electric samples and for the natural gas distribution and electric delivery service operations of each of the Illinois utilities. Staff submits that to estimate the risk of AIU going forward, Ms. Freetly compared the financial strength implicit in the revenue requirement Staff recommends for each of AIU's gas and electric operations to Moody‘s guidelines for electric utilities with medium business risk. Staff notes that although no formula exists for determining an assigned credit rating, Moody‘s provides broad guidelines for the ratio ranges that may be seen generally at different rating levels for regulated electric utilities. The FFO to interest coverage ratio equals interest divided into the sum of FFO and interest. The FFO to debt coverage ratio equals FFO divided by total debt. Each component was based on its contribution to Staff‘s recommended revenue requirement for AmerenCILCO, AmerenCIPS and AmerenIP.

Staff avers that for AIU's gas utility operations, the financial ratios implied by the capital component costs and capital structure are consistent with those of the gas sample, and therefore Ms. Freetly did not adjust the cost of common equity of the gas sample. Staff submits that the electric sample‘s FFO to interest coverage ratio of 4.0X and the FFO to total debt ratio of 18% fall within the guideline range for a Baa credit rating. Staff‘s revenue requirement recommendations, including the capital component costs, are indicative of a level of financial strength that is commensurate with an Aa3/A1 rating for Ameren CIPS and A1 ratings for AmerenCILCO and AmerenIP. Staff posits that this comparison of financial ratios indicates that the electric sample has lower financial strength and therefore higher risk than AIU's electric delivery service operations. Staff notes that financial theory posits that investors require higher returns to accept greater exposure to risk, and that the investor-required rate of return is lower for investments with less exposure to risk. Staff submits that given the difference between the forward-looking financial ratios of AIU's electric delivery service operations and the financial ratios of the electric sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of AIU's costs of common equity for electric delivery service operations. Based on her analysis, Ms. Freetly adjusted the electric sample cost of equity downward 30 basis points, and submits that this 30 basis point adjustment for the electric operations of AmerenCILCO, AmerenCIPS and AmerenIP equals the spread between Baa1 and A1 rated 30-year utility debt yields as of February 13, 2008.

Staff submits that should the Commission accepts AIU's position to update the cost of long-term debt to reflect the recent refinancing of AmerenIP's auction rate bonds, Staff suggests that its updated cost of equity analysis should also be incorporated into the overall cost of capital calculation to obtain concurrent estimates of the costs of AIU's sources of capital. Staff's updated analysis, should the Commission accept AmerenIP's position on the auction rate bonds, indicates that the cost of equity is 10.73% for the natural gas distribution operations of AIU and 10.32% for the electric delivery service operations of AIU.

Staff notes that IIEC continues to recommend a return on common equity of 10.0% for both the electric and gas utility operations of AIU, while CUB recommends a return on equity of 8.955% for AIU gas distribution operations and 9.046% for the electric distribution operations.

b. AIU 's Position

AIU indicates in its Initial Brief that it has decided to accept, for the limited purposes of this proceeding, Staff's recommended cost of common equity. Accordingly, AIU has updated its recommended weighted cost of capital to reflect the acceptance of Staff's determination of the cost of common equity.

c. CUB's Position

CUB submits that it has introduced substantial financial literature which indicates that adhering to past Commission practices will result in an over-inflated return on equity. CUB avers that in order to achieve just and reasonable rates, the Commission should render a decision consistent with this new knowledge and the law and order a return on equity of 8.955% for AIU's gas distribution operations and 9.046% for its electric distribution operations.

CUB notes that a utility's required return on equity, or cost of equity, is the level of profit necessary to attract investment to a business with the utility's level of risk, and if the cost of equity is reasonable and prudently incurred, it is a cost of doing business that utilities have a constitutionally protected opportunity to recover. CUB avers that the Act directs the Commission to ensure that the cost of equity used to develop rates fairly compensates investors for their risk, and assure that customers do not pay an excessive or unreasonable return in the utility‘s rates. CUB submits that these opposing responsibilities can be balanced fairly only when the Commission thoroughly considers the objective market factors that determine a fair return on investment. CUB avers that investors‘ required returns for investment in an enterprise of a given level of risk will change as the objective factors that define the equity markets change over time.

CUB notes that as this necessary cost of equity is not directly observable in the market for a particular utility, financial analysts have developed tools, such as the DCF model and CAPM, to estimate the cost of equity from observable market factors.

CUB notes that AIU initially recommended a return on equity of 11.00% for both its gas and electric operations, based on a DCF, CAPM, other risk premium analyses, and a comparable earnings test, but that AIU has now agreed to accept Staff's return on equity recommendations. CUB notes that Staff recommends a return on equity for AIU's electric distribution operations of 10.68%, and a 10.72% return on equity for AIU's gas distribution operations. CUB submits that Staff's recommendation is based on an average of widely divergent results from its DCF and CAPM analysis. CUB avers that Staff‘s approach is flawed as it ignores recent research on calculating cost of equity. CUB bases its recommendation on the results of a DCF model that incorporate the findings from the most current and advanced studies of financial markets. Based on the results of this model, CUB recommends an 8.955% return on equity for AIU's gas distribution operations and 9.046% return on equity for AIU's electric distribution operations. CUB submits that these represent the returns necessary to maintain AIU's access to equity capital markets on reasonable terms.

CUB submits that Mr. Thomas‘ calculation of rate of return on equity is based on significant financial research, is consistent with the law, and does not result in excessive rates to consumers. Therefore, CUB believes its recommended rate of equity, which is supported by substantial evidence presented in this docket, should be adopted.

d. IIEC's Position

IIEC witness Gorman recommends that the Commission award AIU a return on common equity of 10.0% for both the electric and gas utility operations of each of the AIU utilities. His recommendation is based on the results of his multi-stage DCF model, Risk Premium ("RP") model, and CAPM analyses. In part because the common equity shares of AIU are not publicly traded, Mr. Gorman's analyses applied the models to observable market information for groups of publicly traded utility companies that approximate AIU's investment risk. Mr. Gorman notes that proxy groups were also used by the other cost of equity witnesses in the case.

Mr. Gorman developed one proxy group himself to proxy AIU's investment risk for both gas and electric operations, while the other was the same proxy group used by AIU witness McShane in her cost of equity analyses. Mr. Gorman deemed both groups to have comparable investment risk to AIU, and that within that range of comparable risk, the Gorman proxy group was slightly more risky than AIU, while the McShane proxy group was slightly less risky. IIEC asserts that Mr. Gorman's analyses develop cost of equity estimates using higher and lower risk proxy groups that bracket the risk of AIU, and submits that the similarity of his results for the two groups reinforces the appropriateness of his estimates.

IIEC notes that as current economic circumstances can affect the suitability of particular cost of equity modeling techniques for developing cost of equity estimates, Mr. Gorman first investigated the market's current perception of the changing electric utility industry. Mr. Gorman testified that the market sees the industry in a capital spending cycle that is producing very strong growth in rate base, and in related earnings and dividends, which is providing a vehicle for strong growth over at least the next three to five years. IIEC submits that this transitional spending cycle has important implications for estimating a proper cost of common equity and explains Mr. Gorman's use of a multi-stage DCF model.

Mr. Gorman's analyses showed that a two-stage DCF model suggested a return on equity of 9.6%; Risk Premium Analysis, 10.0%, CAPM, 10.4%; and the midpoint-range of his analysis and his recommendation is 10.0%. IIEC submits that this proposed return on equity provides AIU with an opportunity to achieve cash flow credit metrics that will support an investment grade bond rating, allow AIU to maintain its financial integrity, and represents fair compensation for AIU's investment risk and will support AIU's access to credit markets on reasonable terms.

While IIEC recognizes that AIU has accepted Staff's recommended return on equity, IIEC notes that AIU continues to argue against Mr. Gorman's analysis. IIEC submits that its analysis is correct and that Mr. Gorman's recommended return is appropriate.

2. Annual Versus Quarterly DCF Model

a. Staff's Position

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. Staff avers that as a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies. Staff notes that as the companies in Ms. Freetly's gas and electric samples pay dividends quarterly, she applied a multi-stage, non-constant-growth quarterly DCF model.

Staff notes that Ms Freetly modeled three stages of dividend growth. The first, near-term growth stage is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year, while the third or —steady-state" growth rate is assumed to begin after the tenth year and continue into perpetuity.

Staff submits that for the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of February 14, 2008. To estimate the long-term growth expectations for the third, steady-state stage, she utilized the implied 20-year forward U.S. Treasury rate in ten years, 5.15%. The growth rate Ms. Freetly employed in the intervening, five-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. Staff avers that the growth rate estimates were combined with the closing stock prices and dividend data as of February 14, 2008, and based on these growth assumptions, stock price, and dividend data, Ms. Freetly's DCF estimate of the cost of common equity was 9.41% for the gas sample and 10.01% for the electric sample.

While CUB claims that the Commission should use an annual DCF model because the quarterly adjustments to expected dividend yields result in doubly counting the effect of quarterly growth and thus, overcompensate shareholders at the expense of ratepayers, Staff submits that CUB witness Thomas has raised a working capital issue, not a cost of common equity issue. Staff submits that a working capital allowance compensates a utility for any delay between the time it expends cash to provide service and the time it receives cash from its customers for that service, and if a utility has authorized an appropriate working capital allowance, it will receive cash to pay for all costs of service as they come due. Staff avers that if an appropriate working capital allowance is authorized, CUB's argument is invalid because the working capital allowance will eliminate any surplus or deficit in earnings created by the timing of the utility's cash collections and disbursements. Staff submits that because utility companies pay cash flows (i.e., dividends) over the course of a year and not all at the end of the year, use of a quarterly DCF model is not only appropriate for rate setting purposes, it is necessary for a utility to recover its true cost of common equity. Staff also notes that the Commission has explicitly rejected the use of an annual DCF model in previous proceedings. Staff argues that CUB's models variously ignore the time value of money, ignore the investor required return, and understate the cost of equity.

Staff submits that the argument regarding the use of a quarterly DCF versus an annual DCF model is a basic question of the time value of money, and note that CUB acknowledges the greater value of quarterly dividends relative to a single, annual dividend of the same total amount paid at the end of the year.

b. CUB's Position

CUB notes that DCF estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future, and DCF uses current stock price and expected cash flows from dividends and earnings growth to estimate the return that investors expect to receive. CUB submits that investors' expectations of growth and cash flows are driven largely by historical experience, and that analysts are frequently overly optimistic.

In calculating the return on equity using DCF, CUB witness Thomas began with the same samples of comparable utilities used by AIU. Mr. Thomas removed eleven companies from the electric sample and one company from the gas sample as, in his opinion, their levels of historic growth were not sustainable. Mr. Thomas posits that inclusion of these companies introduces inappropriate bias into the sample.

CUB submits that it has introduced evidence that showed that the quarterly adjustments to expected dividend yield result in double counting the effect of quarterly growth and thus overcompensates shareholders at the expense of ratepayers. CUB avers that the use of any method that double-counts the effect of quarterly growth, and overcompensates investors at the expense of rate payers is inconsistent with the law and must be rejected.

CUB argues that this double-counting problem arises because investors, who receive their dividends quarterly, are able to reinvest their dividends and realize returns on those reinvestments. CUB submits that should the Commission authorize an adjustment to DCF to account for quarterly growth and compounding, the Commission increases the returns that it grants investors, while those investors are already earning more because of the timing of their dividend payments.

CUB posits that Staff and AIU inappropriately rely on outdated studies and findings from financial literature. CUB opines that Mr. Thomas relies on more recent and uncontroverted financial literature, which reveals the cost of equity should actually be much lower than Staff's estimates. CUB submits that recent studies have shown that CAPM contains a substantial bias, and is unreasonable to rely on to estimate a utility's cost of equity.

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3. Growth Rates

a. AIU's Position

AIU notes that IIEC witness Gorman‘s uses a two-stage DCF model that relies on two separate measures of investor growth expectations; the consensus of analysts‘ forecasts of earning growth for five years, followed by the consensus forecast by economists of long-term nominal growth in the economy as a proxy for the growth rate that utility investors expect into perpetuity. AIU submits that Mr. Gorman‘s two-stage DCF model represents a departure from his past practice, and notes that in prior proceedings before this Commission and other regulatory commissions prior to 2008, Mr. Gorman had relied solely on a single-stage constant growth DCF model. AIU posits that in this proceeding, Mr. Gorman has abandoned the constant growth model, on the grounds that the results are too high, because the analysts‘ forecasts of growth are too high to be sustainable.

AIU notes that this does not mean that Mr. Gorman is wrong for using a two-stage DCF model as one of his tests to estimate the cost of equity, as AIU witness McShane also used a two-stage DCF model as one of her five tests to estimate a fair return on equity for the AIU. AIU submits however, it is not reasonable to discard the results of the constant growth test, which is based on the more objective measure of investors‘ growth expectations than the two-stage model. AIU posits that a reasonable approach would be to give equal weight to the results of the constant growth and two-stage models. AIU submits that the result of Mr. Gorman's constant growth DCF model, applied to his sample of electric utilities, is 11.66%, and giving equal weight to both the constant growth and two-stage model changes Mr. Gorman's DCF result to 10.6% (average of 9.6% and 11.7%).

AIU avers that Mr. Thomas recommends historic internal growth in the application of the DCF test, which AIU submits is not reasonable. AIU posits that the use of historical internal growth rates measured over a specific period, is a purely subjective choice on Mr. Thomas' part, with no objective link to investor expectations for the future that are embedded in current stock prices. AIU submits that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. AIU notes that the average achieved returns on equity over the 2002-2006 period that Mr. Thomas relied on were 12% for his gas sample and 11% for his electric sample, and according to the Value Line forecasts that Mr. Thomas provided, the samples are forecast to earn 11.9% and 11.7%, for gas and electric respectively, during 2010-2012.

While Mr. Thomas suggests investors are expecting utilities to earn only a 9.0% return on equity, AIU submits that Mr. Thomas fails to acknowledge that dividend payout ratios have declined for both his samples during the 2002-2006 period, and are expected to decline further. AIU notes the dividend payout ratio for Mr. Thomas' electric sample was 70% in 2002, but had declined to 61% by 2006, and are forecast to decline further to 57% in 2010-2012. AIU notes that failure to properly take this decline into account will result in an understatement in the ―bx r" internal growth rate. In Mr. Thomas' electric utility sample, the average retention rate over the period 2002-2006 was 35%, while the forecast 2010-2012 retention rate is 43%. AIU argues that failure to recognize the higher retention rate would understate expected growth. AIU submits that by focusing on internal growth only, Mr. Thomas fails to consider any sustainable growth from external financing (the "SV" component of sustainable growth), and notes that failure to include the SV component can seriously understate the expected sustainable growth rate. This is particularly true during periods when utilities need to raise substantial amounts of capital to invest in infrastructure. AIU recommends the Commission reject Mr. Thomas' DCF method, and thus his recommended return on equity.

b. Staff's Position

Staff opines that CUB witness Thomas' position on the issue of growth rates is not clearly thought out. Staff notes that on one hand he argues that analyst growth rate forecasts should not be used exclusively, yet he ignores analyst growth rate forecasts when performing his DCF analysis and relies solely on a ―bx r" growth rate estimate derived from historical data. Staff notes that this approach produces a growth rate of 4.21% for his electric sample, which is 39% lower than the lowest of his four analyst EPS growth rates (6.91%) and 52.5% lower than the highest of his four analyst EPS growth rates (8.86%) noted in his testimony. Staff submits that Mr. Thomas' ―bx r" approach produces a growth rate of 4.69% for his gas sample. Staff suggests that if Mr.

Thomas had given weight to any of the analyst growth rates in his DCF analysis, the resulting costs of equity would have been higher than his recommendations of 8.955% for gas and 9.046% for electric.

While Mr. Thomas cites several studies in support of his conclusion and implies that those studies can be applied to utility growth rates, Staff avers that those studies do not support his position. Staff suggests that the studies he cites report generalized findings for all common stocks, and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth. Staff notes in contrast, a study that indicates analyst growth rate estimates for utilities are not overstated.

Staff avers that the financial literature that Mr. Thomas cites study whether or not analysts' growth estimates are too high relative to achieved growth, as measured after the fact, and as such, they are ex post assessments of analyst growth rates' ability to accurately predict future growth, not assessments of analyst growth rates' value as estimates of investors' ex ante expectations. Staff notes that as investors' growth expectations are forecasts of the future, they may differ significantly from the ex post achieved growth. Staff submits that a cost of equity witness attempts to estimate investors' true growth expectations, irrespective of their accuracy as predictors of future growth. Staff posits that as long as analyst growth rates reflect investors' true growth expectations, use of analyst growth rates will accurately estimate the cost of equity, if properly applied in a correctly specified DCF model. Staff submits that Mr. Thomas incorrectly implies that analyst growth rates should be judged on their ability to accurately predict future growth, rather than on their value as proxies for investors' ex ante expectations.

Staff notes that Mr. Thomas argues that in circumstances where the dividend payout ratio is expected to change, use of the growth formula "b x r" to estimate expected future growth is superior to analysts' forecast. Staff notes that while Mr. Thomas indicates that Value Line's EPS and dividends per share (―DPS") growth expectations differ and neither correctly measures investor expectations, Staff notes that his solution rejects both and substitutes a growth rate that is almost a full percentage point less than either the EPS or DPS growth projection.

Staff submits that Mr. Thomas inappropriately extrapolates from a single source to suggest that investors, generally, are expecting dividend payout ratios to change. Staff notes that the difference between the Value Line dividend growth rates and earnings growth rates is not very large, and Staff submits that this does not indicate changes in dividend payout ratios beyond normal year-to-year fluctuations. Staff opines it is unrealistic to expect dividend payout ratios to remain absolutely constant in the near term. Staff further opines that Value Line's growth normalization technique for calculating forecasted growth rates is too mechanistic to ensure proper normalization. Staff submits that Value Line takes a simple three-year average of the base line data, such as EPS and DPS, to approximate the results of normal operations, however, if that three-year base is abnormally high, the growth rate indicated by the forecasted EPS or DPS will be lower than appropriate. Conversely, if that three-year base is abnormally low, the growth rate indicated by forecasted EPS or DPS will be greater than appropriate.

Staff opines that even if one were to agree that the divergence of DPS and EPS growth disqualifies either for use in a DCF analysis, CUB's solution is inappropriate. Staff submits that when DPS grows more slowly than EPS, sustainable growth must be higher than DPS growth, not lower. Therefore, even if one assumes that the difference in the Value Line growth projections for DPS and EPS is sufficient for rejecting them both, which Staff disputes, the long-term steady state growth rate is higher than the DPS growth rate rather than lower as Mr. Thomas has estimated.

Staff notes that Mr. Thomas used historical dividend payout ratios and returns on equity to derive his b x r growth estimate, which he then added to the current dividend yield of each company in his samples to derive his cost of equity estimates. Staff avers it is inconsistent to apply a growth rate that reflects historical dividend payout ratios with dividend yields that reflect current dividend payout ratios for two reasons. Staff submits that growth rates derived from historical data are inconsistent with the prospective nature of the cost of common equity. Staff further notes that Value Line EPS and dividend per share growth data indicate that the average dividend payout ratio for his sample is expected to fall from 2004-2006 to 2010-2012. Staff posits this indicates that the retention ratios (i.e., retention ratio = 1 - dividend payout ratio) were lower during the period from which Mr. Thomas derived his b x r growth rate (2002-2006) than expected going forward, all else being equal. Conversely, it indicates that Value Line projects lower dividend payouts going forward, which would produce a lower dividend yield, all else equal. Staff submits that Mr. Thomas combines the lower retention growth rates from 2002-2006 with the lower current dividend yields, which understates the cost of equity.

Staff opines that numerous studies have shown that analyst growth rate estimates are the best proxy for investor expectations, and that analysts' forecasts are better predictors of actual growth rates than are predictors based solely on historical information. Staff submits the results of valuation models, such as the dividend growth model, are typically more accurate when the growth rate comes from analyst forecasts.

Staff notes that while CUB urges the Commission to adopt its estimates of sustainable growth using the internal growth method, claiming that academic literature concludes that historical growth rates are a far more accurate predictor of expected sustainable growth, Staff submits that the academic literature does not indicate that utility growth rates appear to be upwardly biased or demonstrate that analyst growth rates are poor proxies for investor growth expectations.

c. CUB's Position

CUB suggests the Commission adopt Mr. Thomas' method of computing growth rates, which estimates sustainable growth rate using the internal growth method. CUB submits that Mr. Thomas' analysis avoids reliance on analyst growth estimates and takes into account changes in expected dividend payout ratios. CUB notes that it, Staff and IIEC agree that analysts' are currently producing overly optimistic growth forecasts that are unlikely to be sustainable over time. CUB submits however, while recognizing that analysts produce overly optimistic growth forecasts, Staff's and IIEC's subjective determination of how growth rates might change is inaccurate, and therefore, should be rejected in favor of the internal growth method.

CUB avers that the sustainable growth rate is a critical component of the DCF model, representing the amount of growth that investors expect to occur on their investment, and that is sustainable over the long-term. CUB submits that setting the growth rate component of the DCF model at an unreasonably high level would result in an estimate of the cost of equity that is also unreasonably high, all other things being equal.

CUB opines that historically, analysts have set their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB asserts that to deal with this problem, Staff and IIEC have adjusted their approach to estimating the cost of equity by using non-constant and two-stage DCF models to account for the optimism of analysts' forecasts. CUB submits that these methods involve significant judgment and introduce a degree of uncertainty into the DCF analysis, which confirms that historical growth rates are a more accurate predictor of expected sustainable growth.

Mr. Thomas addresses both this analyst bias and the bias caused by expected changes in dividend payout ratios, by using the average historic internal growth rate for the sample companies to estimate the sustainable growth rate variable of DCF. CUB says when analysts are expecting the dividend payout ratio to change, their forecasts for both dividends and earnings will not accurately represent expected future growth in the DCF model. Currently, CUB claims analysts are expecting dividend payout ratios to change. Mr. Thomas' estimates of internal growth result in a growth rate of 4.21% for electric utilities and 4.69% for gas utilities. These estimates are considerably below analysts' expected 8.09% growth rate for electric utilities, and 5.20% growth rate for gas utilities. CUB submits that using analysts' growth expectations as the other parties suggest, will overstate the cost of equity.

CUB claims that while AIU argues against Mr. Thomas' use of historic internal growth in the DCF, CUB submits that AIU improperly relies on outmoded and unsupported theoretical arguments. While AIU argues that Mr. Thomas' use of historic internal growth is subjective and has no link to the investor expectations, CUB avers that AIU ignores the most current and relevant academic literature. CUB opines that the latest academic literature supports Mr. Thomas' conclusion that beyond two years, the best forecast of earnings growth is the historical average growth rate.

CUB also disputes AIU's argument that Mr. Thomas' reliance on historic internal growth rates is logically inconsistent. While AIU argues that there is an inconsistency because both past achieved returns on equity and Value Line forecasts of future returns are higher than Mr. Thomas' recommendation, CUB submits that this point actually confirms Mr. Thomas' conclusion. CUB opines that the ―Nagel Paper" makes clear historical average earned returns are unreliable as predictors of future returns.

Further, while AIU claims that Mr. Thomas fails to acknowledge that dividend payout ratios have declined, and are expected to decline further, Mr. Thomas' analysis acknowledges declining dividend payout ratios. CUB notes that because dividend growth is uncertain, the DCF formula uses only the current dividend payment (increased by the expected sustainable growth rate), instead of some analyst's estimated or forecasted dividend payment.

AIU further argues that by focusing on internal growth only, Mr. Thomas has failed to consider growth from external financing, which CUB submits is irrelevant. CUB notes that the internal growth method estimates the maximum level of growth that a company can sustain without injecting more capital into the business, which is consistent with the Commission's practice of granting regulated utilities a return on only their prudent and reasonably incurred investments. CUB submits that evaluating external growth is a highly subjective exercise which relies on questionable assumptions about the future and produces results that are inconsistent with the Commission's practice of granting rates that allow the companies to recover their costs during the test year, including pro forma adjustments.

CUB notes that Staff argues that a study by Chan, Karceski and Lakonishok (the "Chan" study) indicates that analyst growth rates for utilities are not overstated. CUB avers that the Chan study did not conclude that the studies Mr. Thomas relied upon were inaccurate, but instead found that low growth companies, such as utilities, did not behave the same as high growth companies. CUB submits that such a result is hardly surprising and does not undermine the finding that historic average growth rates are the best forecast of earnings growth. CUB avers that Mr. Thomas correctly relied upon studies that show analyst estimates beyond two years are inaccurate.

CUB asserts that it has shown that analysts' growth rates are poor proxies for investor growth expectations, and submits that the Commission must measure equity returns that reflect unbiased growth estimates, rather than upwardly biased analyst forecasts that diverge from the achieved growth rates. CUB avers that using analyst forecasts as estimates of growth will overstate the cost of capital estimate produced by the DCF.

CUB avers that Staff is incorrect when it argues that Mr. Thomas failed to acknowledge changes in the dividend payout ratio. CUB submits that as dividend growth is uncertain, DCF uses only the current dividend payment (increased by the expected sustainable growth rate), instead of analysts' estimated or forecasted dividend payment. As analysts' expectations of growth have been shown to be upwardly biased, CUB asserts that the best measure of growth is clearly the historic internal growth that companies in the sample group have actually experienced.

CUB notes that Staff contends that it is inconsistent to apply a growth rate that reflects historic dividend payout ratios with dividend yields that reflect current dividend payout ratios. While Staff argues that a historic perspective has value in forecasting the future, one can not reasonably forecast the future by looking solely to the past. CUB submits that beyond two years, the best forecast of earnings growth is the historic average growth rate. CUB avers that the studies Staff relies on are outdated and have been superseded by more current studies consistent with CUB's arguments.

d. IIEC's Position

IIEC notes that its witness, Mr. Gorman performed and assessed DCF analyses using both constant growth and multi-stage models. IIEC avers that Mr. Gorman rejected the constant growth model as, in his opinion, its results were based on growth rates that are not sustainable. IIEC opines that because of the current environment, Mr. Gorman and Staff witness Freetly both used multi-stage DCF models in developing their cost of equity recommendations.

IIEC notes that AIU witness McShane argues that Mr. Gorman's two-stage model assumes that investors only expect the forecast of growth to continue for precisely five years, with an immediate change thereafter to the long-term growth in the economy, which Ms. McShane avers creates inconsistencies in the DCF cost estimates for the individual companies. IIEC submits that this criticism demands a level of precision not otherwise required (or often seen) in the use of cost of equity models. IIEC avers that analysts regularly assume the validity of a single growth rate input -- in perpetuity -- in the exercise of their expert judgment. IIEC posits that Ms. McShane's criticism is not valid and should be rejected by the Commission.

IIEC submits that should the Commission accept Ms. McShane's criticism that the growth rate transition may not be as precise and immediate as her view of the two-stage model demands, then IIEC suggests at most ,Mr. Gorman's two-stage model uses a questionable expected growth input for a 1-3 year period of transition. IIEC notes that the Commission can only surmise at what point investors would expect the analyst's forecast growth rates to decline to levels that more closely track the growth in the economy. IIEC posits that underestimating the period over which the forecast growth rates are expected to prevail understates the cost of equity when the forecast growth rates exceed the long-term equilibrium growth rate and overstate the cost of equity when the converse is the case. IIEC submits that giving equal weight to the constant growth and two-stage DCF models is not a reasonable approach, under these circumstances.

While AIU contends that it is not reasonable for IIEC to discard the results of the constant growth test, IIEC notes that AIU admits that ―the growth rates analysts are forecasting are not sustainable in the long-term," as is required for a constant growth DCF model. IIEC notes that Mr. Gorman's decision not to use a constant growth DCF model was the result of a detailed evaluation of the reliability of that model in the current environment. Mr. Gorman posits that near term analysts' growth estimates are too high to be sustainable as long-term growth rates, similar to Staff's conclusion on this issue. Although AIU alleges that Mr. Gorman has changes his analyses from prior cases, IIEC submits that Mr. Gorman's consistent practice is to test analysts' growth rates to determine whether they are appropriate for use in a constant growth DCF model. Like Staff, Mr. Gorman found current market circumstances did not produce reliable and accurate results in a constant growth DCF model. IIEC submits that AIU presented no credible evidence that a constant growth DCF model using those analyst's near term growth rates that Mr. Gorman rejected would produce a reasonable return estimate. IIEC submits that Mr. Gorman's two stage DCF analysis is appropriate given current circumstances and should be adopted by the Commission.

4. CAPM Analysis

According to financial theory, the required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. The risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Toward that end, Staff witness Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. Staff notes that in the CAPM, the risk factor is market risk, which can not be eliminated through portfolio diversification. IIEC and AIU also utilized the CAPM in there cost of equity analyses while CUB suggests there are significant problems with the CAPM.

a. CUB's Position

CUB submits that recent financial literature reveals CAPM contains a substantial bias, which renders it unreasonable to rely on to estimate a utilities cost of equity. CUB notes that a 2007 study it identifies as the ―Nagel Paper," casts doubt on whether CAPM provides a better estimation of the cost of capital than a completely arbitrary model. CUB submits that the Nagel Paper is the most recent research available on forecast error in CAPM, and corroborates a long history of problems with CAPM.

CUB submits that the Nagel Paper compared a simplified version of CAPM to the mainstream version of CAPM, and five other well-known theoretical models, and concludes that forecast error caused by estimating factor loadings and expected risk premiums in the more complex models exceeds the precision gained by including the risk factors. CUB posits that despite this evidence that CAPM is inaccurate, Staff continues to recommend averaging CAPM results with DCF results to obtain a final recommendation for cost of equity.

CUB recommends that the Commission consider the evidence presented in this case and reject its previous method of averaging DCF and CAPM results to find a final return on equity recommendation. CUB recommends instead using a DCF calculation to estimate return on equity, and suggests the Commission adopt CUB's DCF result of 8.955% for AIU's gas distribution operations and 9.046% for AIU's electric distribution operations.

b. Staff's Position

Staff notes the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required rate of return on the market. For the beta parameter, Ms. Freetly combined betas from Value Line and a regression analysis to estimate the beta of the Gas and Electric samples. For the gas sample, her average Value Line beta estimate was 0.88, while her regression beta estimate was 0.74. For the electric sample, the average Value Line beta estimate was 0.83, while the regression beta estimate was 0.77. For the risk-free rate parameter, Ms. Freetly considered the 2.53% yield on four-week U.S. Treasury bills and the 4.72% yield on thirty-year U.S. Treasury bonds. Both estimates were measured as of February 14, 2008. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.4% and 5.6%. Staff notes that following her analysis, Ms. Freetly concluded that the U.S. T-bond yield is currently the superior proxy for the long-term risk-free rate. Finally, 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 was 13.75% for the fourth quarter of 2007. Staff submits that after inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 12.04% for the gas sample and 11.94% for the electric sample.

5. Beta

a. Staff's Position

Staff notes that CUB challenges Staff witness Freetly‘s beta. Staff claims that Ms. Freetly‘s methodology used to calculate the regression betas for her sample has been approved by the Commission in previous dockets. (Docket No. 02-0837, Order at 37-38; Docket Nos. 02-0798/03-0008/03-0009 (Cons.), Order at 85; Docket No. 00-0340, Order at 25; Docket No. 03-0403, Order at 42) The Order in AIU's last rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), states:

> As the Commission understands it, the Staff regression betas have been calculated in the same manner for several years and, with rare exception, have formed in part the basis for Commission approved returns on common equity. Just as the Commission routinely relies upon both the DCF and CAPM, the Commission believes it is reasonable to rely upon both Value Line and regression betas. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at145)

While Staff notes that CUB witness Thomas claims that betas should not be adjusted for reversion to a market mean of 1.0, Staff submits that the Nagel Paper that he cites actually contradicts his argument and found that a CAPM using raw betas is less accurate in predicting realized rates of return and explicitly rejected use of an unadjusted beta. Staff posits that while the beta parameter is generally derived from historical data, as in theory it should be a forward-looking number, Staff adjusted the raw (i.e., historical) betas for the sample companies to improve the accuracy of the beta estimates. Staff submits that the Armitage text Mr. Thomas cites with regard to this argument indicates that studies have shown that such adjustments result in appreciably better forecasts, finding that the reduction in both bias and inefficiency is greater the further away from one the beta in question is. Staff notes that Armitage states that the observed flatness of the Securities Market Line is due to two factors: 1) error in the estimation of true betas (i.e., the further above (or below) the mean an observed beta is, the more likely it is that the estimate error is positive (or negative)) and 2) regression toward the mean (i.e., moderation in risk over time).

While Mr. Thomas concludes that mean reversion for utilities with betas below 1.0 is wrong, citing a Gombola and Kahl article that suggests that utility betas actually revert to a utility average beta rather than a market mean beta of 1.0, Staff submits the derivation of the true industry mean beta is problematic. Staff avers that not only is any estimate of the true industry portfolio beta mean dubious, as betas change over time, but notes the farther below the market mean a raw beta is, the more likely its estimate error is to be negative. Staff posits that the average of a portfolio of low betas, each of which is likely to be biased downward, will, itself, likely be biased downward. Staff submits that Mr. Thomas' proposal to ignore beta reversion altogether and use an unadjusted beta was explicitly rejected in the Nagel Paper, and should be rejected by the Commission in this proceeding.

b. CUB's Position

CUB argued that the evidence presented in this case shows that CAPM is highly inaccurate, and suggested the Commission reject any rate of return that includes CAPM in the calculation. CUB submits that should the Commission use CAPM in setting the return on equity, the Commission should reject Staff's and IIEC's CAPM analyses as they use adjusted betas that result in even greater inaccuracies.

CUB notes that the beta parameter represents the degree to which the price of a stock moves with the overall market, and if the stock in question is less volatile (and hence, less risky) than the overall market, then its beta parameter will be less than 1.0, while if the stock is more volatile and risky than the overall market, then its beta parameter will be greater than 1.0. CUB submits that in the context of a CAPM analysis, an unreasonably high choice of beta parameter will result in an unreasonably high cost of equity.

CUB avers that while the Commission has historically relied on beta parameters that have been adjusted using the mean reversion adjustment, this adjustment is reasonable only under certain circumstances – when a company's beta can be expected to move toward 1.0 over time. CUB submits that utility stocks have not been shown to have beta parameters that move toward 1.0 over time, and argues that financial researchers have found that an underlying mean of 1.0 is too high for most utilities, and theorizing that utilities revert to a utility average beta.

While Staff attempts to refute this evidence by arguing that a portfolio of betas below 1.0 will be biased downward, CUB avers that Gambola and Kahl have already proven that the mean reversion adjustment methodology does not apply to utilities, and there is no basis with which to conclude that a portfolio of utility betas will somehow behave any differently than individual utility betas. CUB submits that the mean reversion adjustment incorrectly increases CAPM estimates of utility cost of equity, is inappropriate for use in a utility rate making proceeding, and should be rejected by the Commission.

c. IIEC's Position

IIEC posits that in recent years, electric utilities have implemented corporate strategies that have decreased their operating and financial risk factors. Specifically, they have pursued back-to-basics investment strategies that lower their operating risks, and they have divested non-regulated businesses to reduce debt and strengthen their balance sheets. IIEC submits that these trends are confirmed in the published observations of capital industry institutions like Value Line, which notes an increase in the common equity ratio and fixed charge coverage ratio of such utilities over the last three to five years, further lowering financial risk. IIEC avers that these risk reductions have resulted in robust stock return performance for electric utility stocks.

Mr. Gorman observed that over the last five to ten years, utility betas have exhibited an upward trend that is not associated with an actual increase in risk, rather, the apparent increase indicated by the high betas reflects that utility stocks have outperformed the market. Recognizing these market developments, Mr. Gorman employed a beta of 0.85 in his CAPM analysis, which IIEC submits is appropriate and should be adopted by the Commission.

6. Expected Risk Premium

a. AIU's Position

AIU submits that Mr. Gorman‘s CAPM takes an improper approach to estimating the market risk premium. AIU notes that he estimates the market risk premium in two ways. For one method, he adds the average historic real return on equities to the long-term forecast of inflation to arrive at an estimate of the future market return of 11.6%. From that estimated market return, he subtracts the forecast risk-free rate of 4.6% to arrive at an estimated market risk premium of 7.0%. His second approach takes the nominal historic return on equities from which he subtracts the historic achieved total return on government bonds (5.8%), arriving at a market risk premium of 6.5%.

AIU asserts that with respect to the first approach, adding the real return achieved on the market to expected inflation would be appropriate if there were any evidence that the expected return on the market moves in tandem with the rate of inflation, however AIU posits that there is no such evidence. AIU submits that in the absence of any observable relationship between inflation and real returns, or any indication that there is any secular upward or downward trend in the nominal market returns, the nominal achieved market return is the better estimate of the forward looking market return. AIU notes that the nominal market return, as utilized in Mr. Gorman's second approach, is 12.3%, leading to a market risk premium over his 4.6% forecast risk-free rate of 7.7%.

AIU avers that Mr. Gorman's second approach to estimating the market risk premium entails subtracting the historic total return on government bonds (income return, capital appreciation return and investment return) from the total return on the equity market composite. AIU notes that the estimation of the market risk premium, requires the use of a proxy for the risk-free rate, and submits the total return achieved on government bonds is not the appropriate proxy for the risk-free rate, but instead the income return, not the total return, on bonds should be used as the proxy for the historical risk-free rate when estimating the expected market risk premium ("EMRP").

AIU posits that another consideration when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. AIU notes that the total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return. The income return is defined as the portion of the total return that results from a periodic cash flow, the capital appreciation return results from the price change of a bond over a specific period, while the reinvestment return is the return on a given month's investment income when reinvested into the same asset class in the subsequent months of the year. AIU submits that the income return is used in the estimation of the equity risk premium as it represents the truly riskless portion of the return.

While Mr. Gorman contends that using total returns on stocks while using income returns on bonds is a mismatch, AIU avers that this in not the case. AIU submits that it is appropriate to use income returns on bonds as the estimate of the ex ante expected risk-free rate while simultaneously using total returns on equities to estimate the expected return on the market. AIU argues there are no observable secular trends in the equity market returns that suggest the equity market returns are not a reasonable reflection of investor expectations, and there is no reason that the total returns on the equity market would not be used by investors to estimate the market risk premium relative to the risk-free rate.

AIU posits that the use of the income return of 5.2% instead of the total return on long-term Treasury bonds of 5.8% results in an equity risk premium of 7.1% (12.3%-5.2%), and the average of the two revised market risk premiums is approximately 7.4%, compared with Mr. Gorman's estimate of 6.75%. AIU submits this results in CAPM return on equity of 10.9% (4.6% + 0.85 X 7.4%), rather than Mr. Gorman's calculated 10.4%.

b. Staff's Position

Staff notes that IIEC witness Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%.

Staff submits that historical risk premiums do not adequately measure investors' current return requirements as historical risk premiums are based on realized returns. Staff avers that due to unpredictable economic, industry-related or company-specific events, the difference between realized and expected returns can be substantial. As such, Staff suggests the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Further, the magnitude of the historical risk premium depends upon the measurement period used. Staff suggests no proven method exists for determining the appropriate measurement period, and therefore historical earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity.

Staff notes the Commission has consistently rejected use of historical data in determining the market risk premium in setting the investor-required rate of return on common equity, and submits the Commission should do so once again in this proceeding. In AIU's most recent rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission rejected Ms. McShane's estimate of the market risk premium and 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. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 142-143)

Staff notes that Mr. Gorman claims Staff's market risk premium estimate is overstated due to Ms. Freetly's DCF derived return on the market, which he claims reflects a growth rate of 11.2%. Although Mr. Gorman presents market risk premiums over long historical periods as measured by Morningstar to indicate that Ms. Freetly's Market risk premium is inflated, Staff submits that historical market risk premiums do not indicate the additional risk premium that common equity investors are expecting in today's market.

Staff suggests that while IIEC claims that the market risk premium presented by Staff is flawed and less reliable than Mr. Gorman's estimated market risk premium range, his calculation of Staff's growth rate does not factor in stock repurchases. Staff posits that Mr. Gorman's failure to consider stock repurchases in his calculation of growth produces an incorrect estimate of the growth rate implied in Staff's calculation of the market risk premium.

Staff avers that CUB witness Thomas presents academic research indicating that the proper expected common equity market risk premium for determining the investor-required rate of return is between 3 and 5%. Staff submits that the research cited represents various academics' opinions of the common equity risk premium investors should expect, not necessarily what the investors truly are expecting. Staff suggests that since the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward, therefore Staff's estimate of the common equity risk premium, derived by subtracting the current yield on long-term U.S. Treasury bonds from the required return on the S&P 500 provides the actual difference between returns on risk-free and risky securities that exists in today's market.

Staff argues that its estimate of the market risk premium provides the actual difference between returns on risk-free and risky securities that exists in today's market, providing the best indication of what investors can expect going forward, and should be accepted by the Commission.

c. CUB's Position

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB notes the EMRP represents the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate. CUB submits the EMRP should be the same for all markets and for all firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk.

Despite the fact that the EMRP should be the same for all markets and firms, CUB argues the other parties in the proceeding use biased analyst estimates of the EMRP using forecasted growth. CUB posits that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP, 5.0%. CUB submits that Mr. Thomas relied on research from independent academics and investors to arrive at his conclusion that analyst-calculated EMRPs often contain significant upward bias. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%.

CUB notes that Staff calculated EMRP using analysts' forecasted growth rates in a DCF analysis of companies making up the S&P 500, which forecasts CUB argues have their sustainable growth rate assumptions at unreasonably and unsustainably high levels. CUB submits the Commission should rely on the greater base of empirical data on which the published studies report and should the Commission use CAPM, use an EMRP of 5.0% in the CAPM.

CUB notes that while Staff argues that Mr. Thomas' EMRP estimate is inaccurate because the relationship between the returns of the stock market and U.S. Treasury bonds is not stable over time and thus current returns provide the best indication of what investors are expecting going forward, CUB submits EMRP is a characteristic attributable to all investors and applies to the full universe of all potential investments. CUB argues the Commission should not ignore available research that confirms that expectations of the EMRP are far below the level that Staff recommends and the EMRPs that have traditionally been approved by the Commission.

d. IIEC's Position

Mr. Gorman made two estimates of the market risk premium for use in his CAPM study. First, he relied on Morningstar data to estimate the actual historical achieved total return on the stock market versus the total return on long term Treasury bond investments. That analysis indicated a market risk premium of 6.5%. Mr. Gorman also used a risk premium study to estimate the forward-looking return on the market less his estimated risk-free rate to produce a market risk premium of 7.0%.

In support of his market risk premium estimates, Mr. Gorman cited actual market data compiled by Morningstar Ibbotson as support for a market risk premium in the range of 6.23% and 7.05%. IIEC avers that Ms. Freetly developed market risk premium estimates using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium estimate of 9.03%. IIEC notes that Ms. Freetly's DCF market return is based on a risk-free yield of 1.9% and growth rate of 11.2%. IIEC submits that the market risk premium estimation alternative presented by Ms. Freetly is flawed and less reliable than Mr. Gorman's as the growth rate estimate in her market based DCF return studies are too high to be used in a constant growth DCF study.

While Ms. Freetly's proposed alternative market risk premium is based on her DCF estimate of the market return, IIEC avers that her result reflects an implicit growth rate (over 11.5%) that simply is not reasonable. IIEC submits the sustainable growth rate for a utility can not plausibly be estimated to exceed the growth rate of the economy in which it operates. IIEC says that assuming growth rates twice the gross domestic product ("GDP") growth rate produces market risk premium results that exceed reasonable estimates like Mr. Gorman's.

Both Ms. Freetly and Ms. McShane challenge the historical market data cited by Mr. Gorman to support his contention that the market risk premium estimates they used are excessive. Ms. McShane contends that the studies are not, in fact, adopted by Morningstar Ibbotson as the estimate of the market risk premium and, as a result, Mr. Gorman's estimate of the market risk premium should be on the order of 7.4%. IIEC submits that whether the Morningstar data were adopted is irrelevant, as Mr. Gorman did not use the data as mere plug-in inputs to his models. IIEC posits that the data represent actual investment returns that Morningstar collected, analyzed and published which Mr. Gorman relied on as this data is useful to investors in forming their expected returns. IIEC argues that Ms. McShane's argument is essentially that the data collected and published by a market institution was, in this instance, useless; which IIEC submits is not a credible argument.

IIEC notes that while Ms. Freetly criticizes any use of historical data to develop expectations for the future, including in expected risk premium analyses, IIEC submits that a CAPM analysis is, in fact, a risk premium analysis that estimates a beta factor from historical data. IIEC avers that Ms. Freetly relies on this risk premium study, including the beta derived from historical data, to support her recommended return for AIU in this case. IIEC argues that Ms. Freetly was unable to deny that her market premium determination is based on a DCF market return estimate that reflects an unsustainable growth rate more than twice the expected long-term growth rate of the national GDP. IIEC posits that her forward-looking market DCF return is inflated and unreliable, which in turn makes her CAPM market risk premium unreliable and flawed. IIEC avers that if Ms. Freetly's CAPM is corrected to reflect a reasonable market risk premium, her analysis also would support a return on equity of less than 10.0%.

IIEC notes that AIU takes issue with Mr. Gorman‘s EMRP estimate used in his CAPM analysis, arguing that the total return achieved on government bonds should not be used as the appropriate proxy for the risk-free rate. IIEC posits that for bonds held to maturity; which IIEC argues is a precondition to long-term yields; the subsidiary return components on which AIU focuses are not a factor. IIEC notes that capital appreciation and reinvestment income, which AIU argues are not risk free, are realized only if the bond is not held to maturity, and they disappear when the bond fully matures.

While AIU also takes issue with Mr. Gorman‘s reliance on the historical real return on the market combined with a forward-looking inflation expectation to estimate EMRP, arguing it would be more appropriate to use the nominal actual achieved return on the market (12.3%), IIEC asserts it is more appropriate to create a forward-looking expected return on the market as Mr. Gorman did. IIEC notes that the nominal return on the market Ms. McShane uses reflects historical inflation, while Mr. Gorman's forward-looking expected return on the market reflects forward-looking inflation outlooks and is incorporated in the market's current valuation of securities.

IIEC claims that while Mr. Gorman‘s method of estimating an expected return on the market does rely on historical data and forward-looking market expectations, this is a widely accepted methodology. IIEC submits that Ms. McShane and Ms. Freetly, in their own CAPM studies, relied on historical data adjusted for forward looking expectations, using Value Line betas and betas calculated using historical stock prices.

IIEC avers that in each case, the beta is estimated from a regression of historical data on stock price variability in relationship to the market price variability, then adjusted to reflect forward-looking risk expectations.

While AIU argues that Mr. Gorman's market risk premium is inconsistent with the historical data and analysis both analysts used, IIEC notes that for her comparison to Mr. Gorman, Ms. McShane relied exclusively on the highest estimated return from the data and a market risk premium of 7.1% while Mr. Gorman used data from Morningstar. IIEC avers that Morningstar indicates that an EMRP reflecting sustainable valuation results can range from 6.2% to 7.1%, depending on the market index used. IIEC submits there is no basis for AIU's argument that only Morningstar's highest market risk premium estimate should be used to estimate AIU's return on equity in this proceeding. IIEC avers that these same arguments apply to Staff's criticism of Mr. Gorman's analysis.

7. Risk Premium Model

a. AIU's Position

AIU notes that IIEC witness Gorman estimates the equity risk premium by averaging the results of two approaches. In the first, the differentials between the regulatory commission authorized rates of return on equity and the yields on long-term U.S. Treasury bonds for the period 1986-June 2007 are determined. Using the 5.2% mid-point of a range of differences of 4.4% to 5.9% (in which 18 of his 22 observations fall), he adds his forecast 30-year Treasury bond yield of 4.6% to arrive at a return on equity of 9.8%. Mr. Gorman's second risk premium approach adds a utility risk premium over utility bonds of 3.7% (mid-point of a range of 3.0% to 4.4%) to the 13-week average yield on Baa rated utility bonds for the period ending February 22, 2008 of 6.5%, producing a cost of equity of 10.2%. The two models are given equal weight, for a return on equity of 10.0%.

AIU submits that Mr. Gorman has incorrectly estimated the risk premium. AIU posits that using regulatory commission authorized returns as the point of departure does not constitute an independent test of the required return on equity; and even assuming that the allowed returns equate to the cost of equity, it is inappropriate to simply average the results for the entire period 1986-June 2007. AIU avers that this approach fails to recognize that there is an inverse relationship between interest rates and equity risk premiums, and use of this approach understates the required risk premiums in the current and forecast interest rate environment.

AIU notes that the required risk premium at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% was estimated from Mr. Gorman's data through a simple regression analysis using the indicated historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. AIU posits that the results indicate that the equity risk premium implicit in the regulatory authorized returns on equity increases (decreases) by 39 basis points for every one percentage point decrease (increase) in the long-term Treasury bond yield.

AIU submits that based on the relationship described above, the equity risk premium and the indicated return on equity at Mr. Gorman's forecast long-term Treasury bond yield of 4.6% is as follows: the indicated risk premium is 5.8% and the indicated return on equity is 10.4%, compared to Mr. Gorman's result of 9.8% calculated using simple average risk premiums.

AIU avers that this same problem exists with Mr. Gorman's risk premium over utility bond yields. At Mr. Gorman's 6.5% utility bond yield, the indicated risk premium is 4.2%, rather than the 3.7% he relied on, for a return on equity of 10.7%, an increase of 0.5% from his reported result of 10.2%.

AIU notes that Mr. Gorman's risk premium test estimate is the simple average of the results of the risk premium over Treasury bond yields and the risk premium over utility bond yields models, and the average of the two revised versions of the models is 10.6% (compared to Mr. Gorman's 10.0%).

b. IIEC Position

In his development of Risk Premium cost of equity estimates, Mr. Gorman used two distinct estimates of the market risk premium to define the range of that factor. The first estimate was based on the difference between the commission authorized returns on common equity and Treasury bond yields, the second on the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields. Mr. Gorman's risk premium analyses produce a return estimate in the range of 9.8% to 10.2%, with a midpoint estimate of 10.0%.

Mr. Gorman avers that his estimated range for the utility equity risk premium is consistent with risk premiums actually found appropriate over a period of almost three decades, adjusted as indicated by prevailing utility bond to Treasury bond spreads. Mr. Gorman asserts that his use of a range of utility equity risk premium estimates, as opposed to a spot estimate, best takes into account the unpredictable variance in the risk premium stemming from changes in investor perception and market conditions.

IIEC posits that while Ms. McShane argues that an inverse relationship between bond prices, inflation and corresponding equity investments needs to be recognized in IIEC's risk premium analysis, IIEC does not agree. While Ms. McShane argues that current lower interest rates mean that the risk premium from Mr. Gorman's analysis should be increased, IIEC suggests this is a simplistic correction for a relationship that is neither simple nor unchanging.

As Ms. McShane recognizes, Mr. Gorman's risk premium test covers a period which has been characterized by both high and low inflation. IIEC submits that his study directly takes account of the unpredictable variances in actual movements of interest rates as well as equity returns, and as it covers a long period, his analysis avoids giving undue influence to possibly anomalous periods. IIEC notes this smoothing effect is supplemented by Mr. Gorman's consideration of current indicators, which gives emphasis to periods that may have more investor influence, as Ms. McShane states is appropriate.

With respect to Mr. Gorman‘s Risk Premium cost of equity estimate, AIU argues that Mr. Gorman —fails to recognize that there is an inverse relationship between interest rates and equity risk premiums" and that he —thus understates the required risk premiums in the current and forecast interest rate environment." IIEC says AIU witness McShane based this conclusion on her regression analysis using historic bond yields as the independent variable and the corresponding risk premiums (allowed return on equity minus the bond yield) as the dependent variable. IIEC claims the relationship between interest rates and equity risk premiums is not constant, may be positive or negative, and can not be predicted with certainty. Consequently, analyses like Ms. McShane‘s are sensitive to the period from which data are taken. Despite the academic research showing a changeable interest rate/risk premium relationship, IIEC claims AIU has provided no evidence that the alleged inverse relationship actually exists today. IIEC submits that the most important attribute of the alleged relationship, for AIU, is that it increases the risk premium and inflates the return on equity estimate.

IIEC submits that Mr. Gorman‘s equity risk premium was derived from data that avoids the unpredictability of the interest rate/equity risk premium relationship. Using Treasury/utility bond yield spreads to track contemporaneous investment risk differences between equity securities and debt securities, Mr. Gorman used this analysis to gauge whether the equity risk premium used in this case should be at, above, or below the average historical level. IIEC notes that Mr. Gorman‘s analysis was based on a measure of investors‘ market risk assessments, and not on an inference of investors‘ assessments, from the unreliable inverse relationship with interest rates.

8. Adjustment for Reduced Risk of Gas Operations

a. AIU's Position

AIU notes that IIEC recommends a downward adjustment to its recommended return on equity of at least 0.50% if the riders proposed by the AIU are adopted by the Commission. AIU submits that this recommendation is purely speculative and Mr. Gorman has provided no indication of whether other utilities in his sample might already have access to similar riders. AIU submits that the proposed QIP rider is to the benefit of customers, not only because it will result in required infrastructure, but because it will reduce the regulatory costs and burden of serial rate proceedings that might otherwise be required, and therefore Mr. Gorman‘s downward adjustment should be rejected.

AIU also disagrees with CUB's recommendation to reduce the return on equity by 67.5 basis points if the VBA rider is approved for the gas distribution operations. AIU posits that CAPM, to which the Commission has traditionally given significant weight, does not provide investors compensation for weather risk, and provides compensation for non-diversifiable risk only. AIU submits that weather is a diversifiable (company-specific) risk. AIU claims that seven of the eight gas distribution utilities in Ms. McShane's sample have partial or full weather protection, thus, any risk-reducing impact of the weather protection on the required return on equity is already reflected in DCF cost of equity estimates.

AIU notes the CUB witness Thomas attempts to place a value on the AIU gas distribution operations' associated with proposed Rider VBA by ―backcasting" the increase in return on equity that the utilities would have experienced between 2002/2003 (prior test years), and 2006, had Rider VBA been operational. AIU notes that Mr. Thomas estimates that with Rider VBA, the actual returns on equity would have been on average 221 basis points higher. As Mr. Thomas notes that the earlier test years were based on 30-year normal weather, while AIU is proposing rates now be set on 10-year normal weather, he attempts to adjust the 221 basis points for the proposed change in weather normalization methodology. AIU avers that Mr. Thomas calculated that AIU's estimated reduction in the variance of heating degree days from normal that is expected to result from switching from 30-year to 10-year normal weather will translate into a similar reduction in the impact that Rider VBA would have on return on equity. AIU submits that Mr. Thomas then reduced the 221 basis point impact to 142 basis points. To account for other factors, AIU notes that Mr. Thomas recommends that the allowed return on equity be reduced by 67.5 basis points.

Mr. Thomas' analysis of the impact on return on equity from moving from 30-year to 10-year normal weather assumes that the 35.85% decline in heating degree day deviations translates into an identical percent reduction in the impact of the Rider VBA on return on equity. AIU submits that Mr. Thomas fails to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced, which AIU claims would have changed the delivery rates required to recover the revenue requirements established for the 2002/2003 test years.

AIU submits that the following table summarizes the average customer usage reflected in the development of residential rates for the 2002/2003 test years compared to the proposed average customer usage based on the 2006 test year.

Company	2002/2003	2006
AmerenCILCO	946	823
AmerenCIPS	899	767
AmerenIP	904	779

While some of the change would have been due to ongoing conservation, AIU submits the majority of the reduction is due to the switch from 30-year to 10-year normal weather. AIU asserts that if the average customer usage proposed in this proceeding had been used to set the delivery rates required to recover the 2002/2003 revenue requirement, the outcome of Mr. Thomas' analysis would have been significantly different. Ms. McShane compared Mr. Thomas' estimates of the impact of Rider VBA on return on equity from the residential classes only to the impact that would have resulted had 2002/2003 delivery rates been set using 2006 test year average customer usage. While Mr. Thomas' analysis produced an average increase in return on equity of 147 basis points had Rider VBA been applied only to the residential rate class, AIU posits that the replacement of the 2002/03 average customer usage with the 2006 test year average customer usage shows that the average return on equity would have decreased by 64 basis points. This suggests to AIU that it would have refunded money to customers, rather than recovering money from customers. AIU submits that while there would have been some decline in average customer usage from conservation since 2002/2003, the impact of Rider VBA would have been negligible.

AIU avers that while Mr. Thomas makes the assumption that the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA translates into a similar reduction in required return on equity, his assumption has no theoretical or empirical basis. AIU notes Ms. McShane's analysis suggests that AIU would have owed customers money if Rider VBA had been in place, while following Mr. Thomas' logic, the cost of equity should increase, which AIU submits does not make sense.

b. Staff's Position

Staff notes that Ms. Freetly did not incorporate the lower risk associated with the Rider VBA revenue decoupling mechanism that AIU proposes in her cost of equity recommendation for the natural gas distribution operations of AIU. Staff submits Rider VBA would effectively separate the gas utility's fixed cost recovery from the amount of gas that it sells, which would result in actual utility revenues that more closely track its projected revenue requirements and should not change with increases or decreases in sales. Staff avers this would give AIU greater assurance that the authorized rate of return will be earned. Staff notes that Moody's states that rate designs that compensate the gas utility for margin losses caused by conservation and weather-related variations in gas consumption stabilize the utility's credit metrics and credit ratings. Staff submits that as the use of a gas decoupling mechanism would reduce risk to a gas utility, a downward adjustment to the rate of return on common equity is appropriate to recognize the reduction in risk associated with the use of a decoupling mechanism.

Staff avers that Moody's analysis of gas utilities focuses on four core rating factors: sustainable profitability, regulatory support, ring fencing, and financial strength and flexibility. Staff submits that among the risk factors reflected in return on equity is the utility's ability to increase earnings despite customer gas conservation, and adoption of a gas decoupling mechanism in a utility's rate design would lower the risk of the utility not achieving the authorized return on equity. Moody's assigns the return on equity factor a 15% weight in determining the overall credit rating score.

Regulatory support considers the strength of the utility's relationship with the regulatory commission. Staff avers that Moody's states that the ability of the utility to recover allowed expenses in a timely manner and its ability to earn its authorized rate of return is a very important component of the utility/regulator relationship. Staff posits a utility‘s score on this factor would be improved with approval of a gas decoupling mechanism since its ability to earn its authorized rate of return would be enhanced. Moody‘s assigns a 10% weight to the regulatory support factor when determining the overall credit rating score.

Staff notes that although Moody‘s does not identify the precise impact that revenue decoupling would have on these two factors, enhancing the utility‘s ability to earn its authorized rate of return would be viewed favorably and could increase the scores assigned to the return on equity and regulatory support factors. Hence, Ms. Freetly assumed that the credit ratings assigned to each of these factors would improve by one credit rating. Since these two factors comprise 25% of the overall weighting, raising the scores for these two factors by one rating would result in a one notch increase in the overall credit rating (i.e., 25% x 3 = .75 rounded to 1). Consequently, if the rating assigned to the return on equity and regulatory support factors is raised by one rating, the overall credit rating for the utility would advance by almost one notch. Staff argues that if the overall credit rating for a company is Baa1 before revenue decoupling, it would most likely improve to A3 with commission approval of a decoupling mechanism. Staff notes the average Moody‘s credit rating for Staff‘s gas sample is Baa1, and the spread between utility bonds rated Baa1 and A3 is 10 basis points. Therefore, Staff recommends that the return on common equity for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP be reduced 10 basis points should the Commission approve Rider VBA to recognize the reduction in risk associated with the use of a gas decoupling mechanism. In the event the Commission approves Rider VBA, the referenced cost of equity adjustment will necessarily result in a reduction to Staff‘s cost of equity recommendations for the gas operations of AmerenCILCO, AmerenCIPS and AmerenIP.

Staff asserts that Rider QIP would also affect the risks and costs of capital of AIU. First, Staff explains, Rider QIP would effectively create two classes of assets from a risk perspective: rate base and Rider QIP assets. Since the riskiness of those two classes of assets could be very different, Staff recommends that the Commission authorize a different rate of return for Rider QIP assets than it authorizes for rate base. Staff does not believe that Rider QIP assets would affect the risk of rate base assets; therefore, Staff does not recommend any adjustment to the authorized rate of return on rate base should the Commission approve Rider QIP.

According to Staff, Rider QIP‘s affect on AIU‘s risk (and thus the costs of capital) is a function of how it would operate. Staff is proposing modifications to Rider QIP in the event the Commission approves such an infrastructure rider. Nevertheless, Ms. Freetly addresses how certain elements of the rider would affect risk. Staff maintains that a downward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would reduce risk, while an upward adjustment to the costs of common equity would be appropriate for each Rider QIP component the Commission adopts that would increase risk.

Staff notes that in comparison to rate base cost recovery, the recovery of the capital costs of projects run through Rider QIP would be more timely. All else equal, Staff states that this reduction in regulatory lag reduces the risk of Rider QIP projects. Should Rider QIP be approved, Staff is further proposing that the rider include a true-up, which Staff submits would increase the probability that the utility will recover all Rider QIP costs, including a return on the capitalized costs, relative to rate base costs. Staff contends that this increased certainty of more timely cost recovery would decrease the risk of Rider QIP projects. Staff submits that nothing in Rider QIP would require AIU to share operating cost savings with customers, which would also reduce the risk of Rider QIP. Staff however is also proposing that the QIP rate be capped so that recovery of the QIP adjustment is discontinued if the utility is earning above the authorized rate of return, which feature would increase the risk of Rider QIP projects because it effectively constrains upside earnings variability of rate base.

Staff indicates that the risk implications of the four Rider QIP components discussed above are cumulative. Therefore, should the Commission: (1) adopt Rider QIP, (2) include a true-up mechanism, (3) not include a pass-through of operating cost savings, and (4) include an earnings cap, Staff contends that four separate adjustments to the Rider QIP cost of common equity would be appropriate. Staff states that the first three adjustments should each reduce the Rider QIP cost of common equity, while the last adjustment should increase the Rider QIP cost of common equity. Staff does not recommend specific cost of common equity adjustments, although Staff agrees that Rider QIP projects would be less risky than projects whose costs are not recovered through a rider, the record contains no analysis-backed quantification of that risk reduction and its effect on cost of capital.

c. CUB's Position

CUB notes that AIU proposes several new riders as part of its filing, and while CUB urges that both Riders VBA and QIP be rejected by the Commission, should the Commission allow either Rider, the Commission should recognize that these riders have an effect on the riskiness of AIU that must be reflected in rates. CUB says that if the Commission chooses to approve Rider VBA, the Commission should reduce AIU's cost of equity by 67.5 basis points. If the Commission approves Rider QIP for AIU's electric operations, CUB argues the Commission should allow AIU to recover only its embedded cost of long-term debt on projects financed under this rider to adjust for the reduced risk AIU has when making such investments.

CUB opines that Rider VBA was proposed to protect AIU and its investors from deviations in monthly sales due to fluctuations in normal weather conditions and reduced customer demand, thereby reducing the risk that AIU will realize revenues below its approved revenue requirements. CUB submits this rider also minimizes shareholder risk due to future reductions in customer demand caused by weather and declining per customer usage, and would also reduce overall operating risk that arises from regulatory lag. CUB argues that these changes are designed only to benefit shareholders, and are simply not necessary to assure AIU's financial stability.

CUB submits the benefits of Rider VBA accrue directly to AIU‘s common equity shareholders, as Rider VBA would provide revenue stability, and enable AIU to increase earnings in the future. CUB submits that the evidence demonstrates that the impact of VBA during 2003 and 2006 would have been to increase the total AIU gas operation return on equity by between 16 and 385 basis points, with an average impact of 221 basis points. CUB submits that the value of Rider VBA to AIU‘s shareholders is much greater than the arbitrary 10 basis points reduction the Commission granted to Peoples for a similar rider. Should the Commission approved Rider VBA, CUB suggests AIU's return on equity should be reduced by 67.5 basis points, which CUB submits is less than half of the impact of Rider VBA, and is less than the impact that weather normalization alone is likely to have on variability in AIU's return on equity.

CUB notes that while AIU argues against Mr. Thomas‘ recommendation to reduce its gas distribution return on equity by 67.5 basis points for Rider VBA, CUB posits that AIU inadvertently supports Mr. Thomas‘ argument that the CAPM is an unreliable model, when it argues that in principle, CAPM does not evaluate weather risk. CUB posits that Rider VBA will produce more stable and certain cash flows that will translate into increased confidence that investors will receive their required return, however, this decreased riskiness is not captured directly in CAPM framework. CUB submits that CAPM‘s failure to evaluate this significant driver of investor returns substantiates Mr. Thomas‘ conclusion about the limited worth of the model.

CUB notes that AIU also argues that, because seven of the eight gas distribution utilities in its witness‘ sample have partial or full weather protection, any risk-reducing impact of the weather protection on the required return on equity is already reflected in the DCF cost of equity estimates. CUB submits that the Commission rejected a similar argument in the recent Peoples rate case, Docket Nos. 07-0241, 07-0242 (Cons.).

CUB avers that AIU argues that Mr. Thomas‘ quantitative analysis of the impact of Rider VBA is inaccurate, failing to recognize the reduction in the average customer usage that moving to 10-year normal weather would have produced. AIU argues that had Rider VBA and 10-year weather normalization both been in place for the residential class during 2002/2003, Rider VBA would have resulted in rate credits rather than surcharges. CUB notes however, that AIU witness Laderoute‘s schedule 14.3 shows there has been a marked decline in the 10 year moving average of heating degree day data for central Illinois since the late 1990‘s. CUB submits that using 10-year weather normal in 2002 would have resulted in per customer usage higher than AIU has proposed in the 2006 test year. CUB avers that to assume that the lower 2006 usage levels approximate normal in 2003 makes little logical sense, and renders Ms. McShane‘s analysis useless to the Commission. CUB notes that in addition, Ms. McShane‘s analysis ignores the impact that Rider VBA would have on the small commercial class, a feature which is necessary to compare the two analyses, nor does she analyze the rising price of gas and its effect on consumption.

CUB also disagrees with AIU's position that there is no connection between the reduction in the differential between the allowed and actual return on equity due to the operation of Rider VBA and the returns earned by investors. CUB submits the benefits of Rider VBA accrue directly to AIU's common equity shareholder as equity holders are exposed to more cash flow risk than debt holders because public utility debt holders are paid first out of a company's earnings, while any remaining earnings then accrue to shareholders through growth from retained earnings and cash flows from dividends. Because Rider VBA provides revenue stability, and will enable AIU to increase earnings in the future, the value of this stability accrues directly to equity shareholders, CUB submits this should be accounted for by reducing AIU's return on equity.

CUB notes that AIU has also proposed Rider QIP for its electric operations. CUB submits that should Rider QIP be adopted, AIU will face significantly reduced risk when investing capital in the plant accounts covered under Rider QIP because the rider guarantees cost recovery, which protects investors from the possibility that they will fail to recover their investment. CUB posits the Commission must properly account for this significantly reduced risk in setting AIU's cost of capital. CUB submits that if Rider QIP is approved, AIU should receive a cost of capital on any investment made under Rider QIP that is equivalent to each utility‘s embedded cost of long-term debt, which AIU has proposed is 6.668% for AmerenCILCO, 6.538% for AmerenCIPS, and 7.975% for AmerenIP. CUB submits this return will allow AIU access to the capital it needs to finance projects under QIP, while recognizing the dramatically reduced risk. CUB believes this recommendation to limit the cost of capital on Rider QIP investments is conservative and the Commission may find that other, additional measures are necessary.

d. IIEC's Position

IIEC notes that AIU is proposing riders that would effectively change the rates set in this proceeding to assure levels of revenues that fully recover, or IIEC suggests possibly exceed, its cost of service. IIEC claims the proposed riders can actually provide AIU with an opportunity to earn more than its authorized return on equity. IIEC submits that rate adjustments, pursuant to the proposed riders, are not based on consideration of all of AIU's revenues, expenses and invested capital, but on only selected elements. IIEC suggests that if the Commission approves the requested riders, then AIU's risk would be reduced, and a reduction to its authorized return on equity would be warranted.

IIEC avers that if either of the proposed Riders if approved, the risk of AIU not recovering its authorized targeted revenues would be shifted to customers (in the form of increased rate volatility), AIU would gain revenue stability, and the market would perceive AIU as a firm with reduced risk. IIEC notes the parties examining the cost of equity effect of the riders do not disagree that approval of one or both riders will have such an effect, however they do disagree on the magnitude of the necessary adjustment to their recommended costs of equity. Mr. Gorman recommends that AIU's recommended return be decreased by an amount in the range of at least 0.5% with rider approval, which would make IIEC's recommended return on equity 9.5% in that event.

IIEC notes that AIU witness McShane acknowledges the risk reducing effect of Rider VBA, and by equating Rider VBA to unspecified weather normalization clauses previously examined by S&P, she concludes that her gas cost of equity recommendation should be adjusted by no more than the 10 basis points. IIEC avers that Ms. McShane is silent about Rider QIP's cost of equity effect, and it appears she believes no adjustment is necessary. IIEC submits she contends that Rider QIP is to the benefit of customers because the rider will result in ratepayers being spared the cost of proceedings to examine AIU's proposed infrastructure projects, while she makes no mention of what AIU gains from approval of the rider. IIEC argues that approval of Rider QIP would certainly benefit AIU and should be accompanied by a reduction in the approved return on equity.

While Staff witness Freetly agrees that AIU's risk will be reduced by Rider VBA, IIEC submits that her recommended 10 basis point reduction is inadequate. IIEC further notes that CUB witness Thomas also finds that Rider VBA will have risk reducing effects that warrants a reduction in the recommended authorized gas returns. IIEC avers that Mr. Thomas' analysis of Rider VBA's revenue and cost of equity impacts would have been had it been in place in the past, causes him to recommend a cost of equity reduction of 67.5 basis points. IIEC notes that he further recommends, if Rider QIP is approved, the Commission authorize a reduced return on Rider QIP electric projects.

IIEC submits that the Commission has before it a record that clearly establishes that approval of one or both of the requested riders will reduce AIU's risk. IIEC believes the principles underlying the Commission's consistent approach to determining the appropriate cost of equity for utilities require recognition of the change in the utility's risk that would accompany rider approval. IIEC avers that Section 9-201(c) of the Act requires that the Commission determine an appropriate cost of equity adjustment, since that is a necessary prerequisite for fulfilling the Commission's statutory obligation to determine just and reasonable rates on this record. Although no party may have suggested the perfect resolution in this case, IIEC submits that Mr. Gorman presents the most reasonable of the positions that accord with the reality of AIU's reduced risk under approved riders.

While AIU criticizes Mr. Gorman‘s recommendation that AIU's cost of equity be reduced by at least 50 basis points as speculative unsupported by analysis, IIEC submits that it is well-supported, and notes that in the recent Peoples case, the Commission approved just such a judgmental adjustment following approval of a similar rider. IIEC notes that AIU does not criticize Staff‘s 10 basis point proposed adjustment, although IIEC submits that Staff‘s analysis of risk reducing factors attributable to the rider was equally judgmental. IIEC avers that AIU suggests an adjustment similar to

Staff's, based on treating Rider VBA like a weather normalization adjustment, despite the rider's much broader coverage.

IIEC argues that AIU does not deny that Rider VBA will have an effect on its revenues, its risk, and on its cost of equity, but simply disagrees with IIEC and CUB on the magnitude of that effect. IIEC submits that the burden is on AIU to prove the reasonableness of its proposed rates, including the reasonableness of the elements that make up those rates, and where other parties have presented sufficient support for a risk adjustment, as here, the utility must rebut that evidence. IIEC avers that AIU has not done so, and the evidence shows that a 10 basis point adjustment is inadequate in this instance.

9. Commission Conclusion

As previously noted, AIU accepts Staff's recommended cost of equity for this proceeding. Staff, CUB, and IIEC each present their own cost of equity analyses. Staff witness Freetly's recommendation is based on a discounted-cash flow analysis and CAPM analysis. CUB witness Thomas utilized a constant growth, annual DCF model to estimate AIU's cost of equity. IIEC witness Gorman used a multi-stage DCF model, RP model, and CAPM model.

The Commission notes that Staff has proposed two recommended cost of equity numbers for AIU, dependent on the Commission's decision on AmerenIP's auction rate bonds. As the Commission has earlier rejected AIU's position on the AmerenIP auction rate PCBs, it appears to the Commission that Staff's recommended cost of equity is 10.72% for AIU's natural gas distribution operations, and 10.68% for AIU's electric delivery service operations.

Before the Commission turns to the details of the parties return on equity estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. The Commission must balance two competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, neither does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary. The Commission recognizes that it must also consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While the Commission recognizes that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record, and consistent with previous Commission decisions, to the extent possible.

a. CAPM

First, the Commission will consider CUB witness Mr. Thomas' recommendation that the CAPM should not be used as a primary tool to estimate cost of equity, but should only be used to check the reasonableness of the DCF model. He contends that CAPM has such bias in its calculations that it is unreasonable to rely on it to estimate cost of equity. The Commission notes it has considered this argument previously, including most recently the IAWC rate case, Docket No. 07-0507. As the Commission noted there, the only new information or argument presented by CUB appears to be the Nagel Paper, which is discussed in the parties' testimony and briefs.

Mr. Thomas argues that the version of CAPM used by the Commission was rejected in the Nagel Paper, as it had a higher forecast error than the more simplified version. While it appears to the Commission that in the Nagel Paper raw or unadjusted betas were used in CAPM, the Commission can find no suggestion, other than Mr. Thomas' testimony, that adjusted betas were excluded due to forecast error. There does not appear to be any support in the record for Mr. Thomas' assumption that a simplified version of CAPM, where all betas equal 1.0, would have a lower forecast error than the traditional CAPM with the use of adjusted betas. Based upon a review of the record, the Commission is inclined to agree with Staff that the Nagel Paper's finding that using a simplified CAPM where beta is set to 1.0 is superior to the use of unadjusted betas, which tends to support use of adjusted betas, rather than unadjusted betas. The Commission does not believe the record supports a finding that the Nagel Paper undermines the usefulness of CAPM in setting market required returns on equity in utility cases. It appears to the Commission that the Nagel Paper in fact supports the long-standing practice of the use of adjusted betas in CAPM rather than unadjusted betas.

Further regarding CAPM, Mr. Thomas urges the Commission to reject the analyses of Staff and IIEC, as both parties used adjusted betas in arriving at their results, and Mr. Thomas suggests that unadjusted betas are superior when calculating a utility's return on equity. The Commission has reviewed the testimony and arguments of the parties on this issue, and does not find CUB's arguments convincing. The Commission is of the opinion that the continued use of adjusted betas, when combined with appropriate proxy groups, is appropriate and should continue.

The next disputed issue relates to the calculation of EMRP used in the CAPM. Staff developed its EMRP using a DCF derived return on the market, proxied by the S&P 500 less the risk-free rate, which produced a market risk premium of 9.03%. Staff used as its risk-free rate the thirty-year U.S. Treasury Bond yield as of February 14, 2008 of 4.72%, while Staff's DCF estimate of the S&P 500 was 13.75% for the fourth quarter of 2007.

Mr. Gorman relied on historical data to calculate two market risk premium estimates for his CAPM analysis. First, he estimated the expected return on the S&P 500 by adding an expected inflation rate of 2.3% to the 9.1% long-term historical arithmetic average real return on the market over the period 1926-2006. He then subtracted the projected yield on U.S. Treasury bonds of 4.6% to determine the 7.0% market premium. Second, he provided a historical estimate of the market risk premium by calculating the difference between the arithmetic average of the achieved total return on the S&P 500 of 12.3% and the total return on long-term Treasury bonds of 5.8% over the period 1926-2006, or 6.5%. Both of his market risk premium estimates were derived based on historical returns on the S&P 500.

CUB suggests that should the Commission continue to utilize CAPM in determining the return on equity, then it should adopt CUB's recommendation for the EMRP that will be used in CAPM. CUB states the EMRP represented the expected return on a perfect portfolio of the entire market, in excess of the risk-free rate, and should be the same for all markets and firms being examined in a CAPM analysis, as it is the beta factors, not the EMRP, that differentiate the return estimates for firms of varying risk. CUB suggests that the EMRP is a characteristic that is attributable to all investors and all potential investments, and therefore there is only one EMRP. CUB submits that surveys of investors show that a reasonable estimate of the EMRP that investors expect is in the range of 3.0% to 5.0%, and CUB recommends using a value of 5.0%.

In the Commission's view, IIEC's first EMRP analysis, wherein inflation is added to the average market return and subtracted from projected Treasury bond yields, fails to consider that the real market risk premium is not stable over time, which seems almost a given, as IIEC averaged data from 1926 to 2006. A major shortcoming in IIEC's second analysis is that it relies largely on historical data. As in previous cases, the Commission finds such an approach unacceptable as an average of historical returns is not a reliable predictor of future returns.

CUB alleges that historical market risk premiums have been shown to be consistently too high. CUB suggests that the EMRP adopted for purposes of this proceeding should be based upon Mr. Thomas' review of opinions of members of the financial and academic arenas, which suggest that surveys of investors show a reasonable EMRP to be between 3.0% and 5.0%. The Commission notes that it previously rejected Mr. Thomas' proposed EMRP based on this same reasoning in the most recent IAWC rate case, Docket No. 07-0507. As the Commission indicated there, Mr. Thomas' suggestion does not seem to allow for the EMRP to change over time, which the Commission believes is necessary for any approach or method adopted. Additionally, the suggested EMRP's by the other parties call into question the validity of Mr. Thomas recommendation.

b. DCF

The Commission will next consider the various issues relating to the DCF model and the inputs thereto. Ms. Freetly applied a multi-stage, non-constant growth quarterly DCF model. Mr. Gorman performed both constant growth and non-constant growth DCF models, however, he rejected the use of the constant growth model as its results were based on growth rates that were not sustainable. Mr. Thomas suggests a constant growth, annual DCF model be adopted. The Commission notes that Mr. Thomas has presented no new evidence in support of the annual DCF model. The Commission strongly believes that the quarterly DCF model should be utilized to estimate the cost of common equity, as demonstrated by numerous previous Commission decisions. It is the Commission's opinion that the use of this model accurately recognizes the timing of cash flows to investors, which is necessary to estimate the investor required rate of return. Use of an annual DCF model, the Commission believes, would unnecessarily introduce measurement error and downward bias to the results.

The Commission notes that it has traditionally relied on a constant growth DCF model with analysts' estimates of EPS growth in developing the cost of common equity for utilities in rate cases. Staff suggests use of a multi-stage, non-constant growth, quarterly DCF model in this proceeding. IIEC suggests the use of a two-stage DCF model, while CUB suggests the use of the constant growth DCF model using historically derived internal growth rates rather than analysts' estimates. Staff and IIEC believe analyst growth rates are so high as to be not sustainable in the long run for use in a constant growth model, and therefore produce too high return on equity results. All parties used proxy groups of gas and electric companies for modeling purposes.

Ms. Freetly modeled three stages of dividend growth for use in her multi-stage, non-constant growth DCF model. For her first stage, she assumed a growth stage of five years. Her second stage is a transitional stage lasting from the fifth to the tenth year, while the third or "steady" stage growth rate begins after the tenth year. For the first stage, Ms. Freetly used the market-consensus expected growth rates from Zacks, for the third-stage she used the 20-year forward U.S. Treasury rate, and the middle stage was an average of the first two rates. The result of her DCF analysis was a suggested return on common equity of 9.41% for the gas sample, and 10.01% for the electric sample.

Mr. Gorman modeled a two-stage, non-constant growth DCF model, where the first stage relied on an average of the consensus of Zack's, Reuters, and SNL Financial to determine analysts expected growth rates for the first stage of the model. For the second stage of the model, from six years to perpetuity, he assumed each company's growth would converge on the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth for the U.S. GDP. His two-stage non-constant DCF model resulted in a 9.6% suggested return on equity.

The Commission notes that it has rejected CUB's DCF model for its continued use of an annual model, rather than a quarterly model. CUB further suggests that the Commission consider historical internal growth rates, rather than analyst's estimates of future growth in the DCF model, arguing that analyst's estimates have been shown to be overly optimistic. The Commission is of the opinion that for DCF purposes, a forward-looking estimate of at least near term growth rates is appropriate, and will decline to adopt CUB's suggestion. CUB's approach has been routinely rejected by the Commission, including very recently in Docket No. 07-0507.

The Commission notes that Staff and IIEC are in agreement that at least in this instance, the use of a single-stage, constant growth DCF model is inappropriate, as analyst's estimates for earnings growth are unreasonably high and are not sustainable for utilities. The Commission agrees with Staff and IIEC that the tradition constant growth model would in this instance, result in suggested growth rates that would exceed the growth rate for the U.S. economy in perpetuity, which appears unlikely. Both Staff and IIEC suggest in this instance, the use of a multi-stage model, with IIEC suggesting a two-stage model, while Staff suggests a three-stage model.

c. Risk Premium Model

Mr. Gorman has also presented the Commission with a risk premium analysis separate from his CAPM analysis. For this model, Mr. Gorman used two estimates of risk premium to develop a range to define the cost of equity. The first estimate was based on the difference between commission authorized returns on common equity, and Treasury bond yields. For the second estimate, Mr. Gorman calculated the difference between commission authorized returns on common equity and contemporary A-rated utility bond yields.

Mr. Gorman's analyses resulted in a return on equity estimate in the range of 9.8% to 10.2%, with a mid-range estimate of 10.0%. It appears to the Commission that Mr. Gorman's risk premium model suffers from the same deficiency as the EMRP used in his CAPM analysis, as it relies on historical returns in an attempt to calculate a forward-looking number. As such, the Commission will decline to use Mr. Gorman's risk premium analysis in determining the authorized return on equity for AIU.

d. Adjustment for Reduced Risk of Gas Operations

While the Commission's complete analysis and decision on Rider VBA and Rider QIP can be found in later parts of this Order, the Commission notes that at this time, it is not authorizing the implementation of either Rider by AIU. The Commission does however, in the Rate Design section of this Order, make the decision to authorize recovery of more of AIU's fixed costs through the customer charge. The Commission is of the opinion that this move toward AIU recovering more fixed costs through the fixed monthly charge will have a similar effect as adopting Rider VBA, in that AIU will be more assured of recovering its fixed costs of service for gas operations. As a result, AIU will face less risk and an accompanying reduction in the authorized return on equity is warranted. Although none of the parties addressed this result directly, the discussions and analyses on the effects of Rider VBA and Rider QIP are helpful to the Commission in its consideration of the appropriate level of reduction in risk associated with increasing the fixed customer charge to account for a greater portion of fixed costs. While the Commission recognizes that this change lessens the risk for AIU to recover fixed gas charges, there is still some risk remaining that reduced natural gas consumption could result in an under-recovery situation. As such, the Commission deems it appropriate to adjust AIU's authorized return on equity for its gas operations downward by 10 basis points. The Commission is of the opinion this reduction adequately reflects the changes adopted in the rate design portion of this Order, and reflects that AIU's risk of not recovering its fixed costs will have been reduced.

e. Authorized Returns on Equity

Having addressed the significant contested issues that relate to cost of common equity, it appears to the Commission, as discussed above, that there are significant shortcomings with respect to the analysis of CUB witness Thomas. The Commission has indicated that it will again decline to adopt his suggestion to use an annual growth DCF mode that incorporates historically derived internal growth rates. Likewise, his suggestions concerning CAPM are rejected, along with his suggested EMRP. Likewise, Mr. Gorman's Risk Premium and CAPM analysis are rejected and will not be considered as they rely too heavily on historical returns in calculating a forward looking recommended return on equity.

The Commission finds value in both Staff's and IIEC's DCF analyses, along with Staff's CAPM analysis. Each has suggested the use of a multi-stage DCF model in this instance to mitigate the impact of unsustainable analyst estimates of growth, using instead estimated proxies of U.S. GDP growth as the long-term growth rate. Staff's DCF analysis, based on a three-stage model, results in a recommended return on equity of 9.41% for AIU's gas operations, and 10.01% for AIU's electric operations. IIEC's DCF analysis, using a two-stage approach, results in a recommended return on equity for both electric and gas operations of 9.6%. Staff's CAPM analysis resulted in a cost of equity recommendation of 12.04% for AIU's gas operations, and 11.94% for AIU's electric operations.

The Commission finds IIEC's DCF analysis, along with Staff's DCF and CAPM analyses, to be without material flaws, and should be considered in establishing AIU's cost of common equity. The Commission further notes that Staff proposes to adjust its recommended electric results downward by 30 basis points, as Staff determined that AIU was less risky than the electric proxy group. The Commission notes this adjustment appears uncontested and it will be adopted for calculating Staff's recommended return on equity.

Having reviewed the evidence and arguments, the Commission concludes that AIU's cost of common equity is 10.68% for gas operations and 10.65% for electric operations. These returns on common equity give equal weight to the results of Staff and IIEC DCF analyses, which is combined with Staff's CAPM analysis. As indicated above, the authorized return on equity for AIU's natural gas operations is adjusted downward by 10 basis points to reflect the change in Rate Design adopted in this Order.

	GAS		ELECTRIC	
Party	DCF	CAPM	DCF	CAPM
Staff	9.41%	12.04%	9.71%	11.64%
IIEC	9.60%		9.60%	
Average	9.51%	12.04%	9.65%	11.64%
Midpoint	10.78%		10.65%	
Risk Adjustment	(0.10)%			
AUTHORIZED RETURN ON EQUITY	**10.68%**		**10.65%**	

10. Commission Authorized Rates of Return on Rate Base

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.01% rate of return on net original cost rate base for electric operations; AmerenCIPS should be authorized to earn an 8.20% rate of return on net original cost rate base for electric operations; and AmerenIP should be authorized to earn an 8.68% rate of return on net original cost rate base for electric operations. The tables below show the development of that authorized rate of return:

Electric Operations
AmerenCILCO

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.65%	4.95%
Total	467,617,514	100%		8.01%

AmerenCIPS

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.65%	5.10%
Total	1,057,618,734	100%		8.20%

AmerenIP

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.65%	5.51%
Total	2,079,219,209	100.00%		8.68%

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.03% rate of return on net original cost rate base for gas operations; AmerenCIPS should be authorized to earn an 8.22% rate of return on net original cost rate base for gas operations; and AmerenIP should be authorized to earn an 8.70% rate of return on net original cost rate base for gas operations. The tables below show the development of that authorized rate of return:

Gas Operations
AmerenCILCO

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	72,643,527	15.53%	4.04%	0.63%
Long-term debt	141,064,706	30.17%	6.65%	2.01%
Preferred stock	36,450,067	7.79%	5.34%	0.42%
Common equity	217,459,214	46.50%	10.68%	4.97%
Total	467,617,514	100%		8.03%

AmerenCIPS

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	55,210,979	5.22%	4.01%	0.21%
Long-term debt	446,741,385	42.24%	6.27%	2.65%
Preferred stock	48,974,984	4.63%	5.13%	0.24%
Common equity	506,691,386	47.91%	10.68%	5.12%
Total	1,057,618,734	100%		8.22%

AmerenIP

Component	Amount	Percentage	Cost	Weighted Cost
Short-term debt	76,677,769	3.69%	3.93%	0.15%
Long-term debt	709,096,036	34.10%	7.34%	2.50%
TFTN	171,533,494	8.25%	4.92%	0.41%
Preferred stock	45,786,945	2.20%	5.01%	0.11%
Common equity	1,076,124,965	51.76%	10.68%	5.53%
Total	2,079,219,209	100.00%		8.70%

VII. PROPOSED RIDERS

Among the Proposed Tariffs filed by AIU are its proposals for several new revenue generating riders. Rider UBA-Uncollectibles Balancing Adjustment, Rider UBBA-Uncollectibles Balancing Base Rate Adjustment, and Rider UBPA-Uncollectibles Balancing Purchased Power Adjustment concern amounts billed to electric and gas customers that have not been paid. Although it continues to believe that the manner in which it recovers uncollectibles warrants further consideration, in his rebuttal testimony, AIU witness Nelson indicated that AIU is withdrawing its request for approval of these three riders concerning uncollectibles. (See Ameren Ex. 18.0 at 5) Other proposed riders that AIU still supports are Rider VBA-Volume Balancing Adjustment ("Rider VBA"), applicable to residential and small commercial gas delivery service customers, and Rider QIP-Qualifying Infrastructure Plant Surcharge ("Rider QIP"), applicable to electric delivery service customers. Rider VBA and Rider QIP will be considered separately below.

A. Rider VBA

1. AIU's Position

The two components of AIU's gas cost of service are gas supply and gas delivery. The cost of the natural gas supply itself is recovered through the PGA rider. About 97% of gas delivery cost is recovered through tariff base rates primarily consisting of customer charges, volumetric delivery charges, and, for certain larger customer groups, demand charges. The remaining portion (about 3%) of delivery service cost is recovered through —other” tariff charges (e.g., late pay charges, insufficient fund charges, disconnect/reconnect fees, etc.). Of the fixed delivery service cost recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service cost recovery comes from the monthly customer charge.

Because a significant portion of its fixed costs are recovered through the volatile volumetric component, AIU observes that it could significantly over- or under-recover the cost of service from year to year due to fluctuations in usage. AIU indicates that such fluctuation has occurred, but that it has been decidedly one-sided. AIU reports that the level of sales it has experienced has been consistently lower than that assumed in the test year, even in the very first year after a rate order. According to AIU, this has caused it to under-recover its cost of service, and thus it has not earned the authorized rate of return.

The three principal factors that AIU identifies as being responsible for sales differing from forecasted levels are (1) weather, (2) a general decline in natural gas usage, and (3) targeted gas energy efficiency measures. With regard to weather, when recovering fixed costs through volumetric rates, smaller customers are apt to pay more toward fixed costs in colder weather when they use more gas for heating and pay less toward fixed costs in warmer weather when they do not use as much gas for heating. Gas usage is also generally declining across the industry according to AIU, so any efforts to recover fixed delivery costs through a volumetric rate will likely suffer over time. AIU attributes at least some of the general decline to gas appliances becoming more efficient and there being no significant new domestic uses for gas. Despite this explanation for the decline in gas usage, Mr. Nelson indicates that AIU has not yet experienced much of an impact from the third factor.

AIU also points out that volumetric delivery rates pose a problem in regard to energy efficiency initiatives. When utility revenue is tied to the volume of gas sold, AIU observes that the utility has no incentive to encourage conservation and the efficient use of gas. If this disincentive is removed, AIU witness Hanser indicates that AIU is willing to participate in a collaborative stakeholder process to identify specific energy efficiency measures to be implemented and the amount to be expended on each.[9]

AIU seeks to remove this disincentive by "decoupling" the recovery of fixed delivery service costs from the amount of gas sold through its proposed Rider VBA. Generally, under a decoupling rider, on a periodic basis revenues are —trued-up" to the predetermined revenue requirement using an automatic rate adjustment. The result is that the actual utility revenues should more closely track its projected revenue requirements, and should not increase or decrease with changes in sales. Citing research conducted by the National Association of Regulatory Commissioners ("NARUC"), AIU relates that ten other states have approved decoupling and three states and the District of Columbia are investigating decoupling. AIU adds that 13 of the 14 states mentioned also have energy efficiency programs. AIU adds that energy efficiency programs conducted in conjunction with a decoupling rider provide societal and economic benefits, which ultimately benefit customers.

If the Commission is inclined to approve Rider VBA, AIU states that Rider VBA is designed to operate in the same manner as the Peoples/North Shore decoupling rider

[9] AIU filed with the Commission proposed gas efficiency measures resulting from the collaborative effort, initiating Docket No. 08-0104. The gas efficiency filing identifies the definitive programs, the associated cost of the programs, and a proposed rider for recovery of the costs. Docket No. 08-0104 is currently on-going.

approved by the Commission as a four-year pilot program in consolidated Dockets Nos. 07-0241 and 07-0242 on February 5, 2008. Rider VBA would adjust customer rates each month based on changes in per customer usage for the residential (GDS-1) and small commercial (GDS-2) customer classes based on an AIU-configured usage-per-customer benchmark. A monthly surcharge would be imposed if per-customer usage in the rate classes falls below a baseline set in this proceeding (regardless of the reason for the decline), without examining whether overall revenues have increased. AIU has agreed to implement Rider VBA in the context of a pilot program that would terminate on December 31, 2012. AIU is also willing to provide the Commission with an annual report of the rate of return of AmerenCILCO, AmerenCIPS, and AmerenIP and the effect on that return of Rider VBA. AIU further agrees that the Rider VBA formula should be designed to recover only the utility‘s fixed costs that are reflected in the revenue requirement recovered via the volumetric delivery charge.

These commitments, AIU argues, sufficiently counter the concerns of AG/CUB witness Brosch that the Commission will inadvertently allow unreasonable earnings when it evaluates rider recovery of costs on an annual basis. To the extent that the rate of return reports are not sufficient, AIU states that the Commission can request further information, which AIU has a duty to respond to pursuant to Section 5-101 of the Act. The "pilot" nature of Rider VBA should also help to resolve the concerns of Mr. Brosch because if renewal of the rider is desired, changes can be made based upon what stakeholders have learned from the pilot program

AIU also responds to Mr. Brosch's assertion that Rider VBA is asymmetrical, in that it only benefits AIU. AIU insists that Rider VBA is plainly symmetrical, meaning that if a colder than normal winter were to occur customers would receive credits for the higher than anticipated consumption and vice versa. AIU witness Cooper even testifies that had Rider VBA been in place this past winter, customers would have received credits in three of the four winter months. AIU contends that Rider VBA will simply track the volumetric cost collection per customer and true-up to prevent either the under- or over-recovery of Commission approved fixed costs for test year customer levels. Moreover, setting aside the question of symmetry for a moment, AIU notes that Mr. Brosch does not address the central issue: that given today‘s contemporary fossil fuel issues, establishing rates that give utilities an incentive to sell more natural gas is a policy that no longer makes sense.

AIU further contends that the AG's legal arguments against Rider VBA are misplaced. Citing Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 123-9 (1995), AIU asserts that the Commission has discretion to allow rider recovery in a proper case and the legal authorization to approve riders will not be reversed absent an abuse of discretion. Under City of Chicago v. Illinois Commerce Commission, 218 Ill.App.3d 617, 628 (1st Dist. 1996), AIU also states that rider recovery is not limited only to circumstances where unexpected, volatile, and fluctuating costs are present.

In response to Staff witness Ebrey, AIU denies that Rider VBA represents only "partial" decoupling since it would not reflect changes in the number of gas customers. In contrast to Ms. Ebrey‘s proposal and commentary, AIU states that it is not seeking to isolate its revenue from —all changes” that may occur in the course of the operation of its gas utility businesses. Rather, AIU indicates that it is seeking to decouple Commission approved rate recovery for test year customer levels from changes in volumetric consumption, specifically due to declining usage trends and weather patterns. AIU characterizes Rider VBA as "plain vanilla" decoupling, and asserts that it is not intended to operate differently from what was granted in Docket Nos. 07-0241 and 07-0242 (Cons.). AIU insists that Rider VBA is —full decoupling" since the volumetric component of its rates are to be trued-up on a margin per customer basis to insure each customer pays his/her share of fixed costs.

If actual (i.e., post test year) customer count data is incorporated, AIU maintains that Rider VBA no longer remains a rate design vehicle designed to recover Commission approved revenue requirements for test year customer levels. Rather, it becomes a broader formulaic rate that essentially will function to alter the revenue requirement equation established by the Commission in this docket on an annual basis. Additionally, AIU contends that Ms. Ebrey's method would do so asymmetrically because her recommendation has not articulated any mechanism by which AIU would be permitted to include costs associated with changes in the number of customers, or by which AIU would be permitted to prove up the value of the plant assets necessary to meet customer growth. Such a situation, AIU argues, essentially amounts to single-issue ratemaking.

Under Ms. Ebrey's proposal, AIU claims that the lack of symmetry would be so prejudicial to its interests, that it would be confiscatory. Essentially, AIU continues, Ms. Ebrey‘s proposal would function to annually reduce AIU rates by spreading the revenue requirement across a broadening customer base as new customers are added while it completely ignores costs associated with such load growth. Thus, AIU contends that it is inevitable that a changing or increasing cost of service due to plant and expenses associated with new customers with unchanging revenue would not afford AIU a reasonable opportunity to earn the rate of return approved by the Commission herein.

Conversely, AIU points out that it is not explained how customers would be impacted by the potential of an automatic rate increase if customer numbers were to contract in a given year. It is not clear how such a situation would fit within the constructs of the Act. While it is uncommon for customer count reductions to occur, AIU contends that demographic shifts such as population decline in certain areas, or sudden and dramatic increases in natural gas cost can result in customer count reductions. Without any consideration in the record of such issues, AIU urges the Commission to decline to add customer count variables to the Rider VBA formula.

With respect to Staff's assertion that it would be illogical to have identical decoupling pilot programs for both AIU and Peoples/North Shore, AIU believes otherwise. AIU contends that having multiple gas utilities in Illinois with the same pilot program insures that the results of the pilot program are not skewed by some operational condition a single utility. Under its proposal, AIU states that the Commission will have a diversity of data to analyze.

An alternative to Rider VBA that would still promote full fixed cost recovery by the utility is recovery of all fixed delivery costs through a fixed monthly charge to all affected customers. Under such a rate design, AIU states that utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. AIU indicates that it can either implement the fixed monthly charge concept as described above, or implement Rider VBA which would continue to retain a volumetric rate design component and, also, ensure a precise match between actual revenue and those previously approved by the Commission. Another alternative, AIU continues, would be to adjust the test year billing determinants for a downward trend in sales due to efficiency gains, but this is the less preferable option because it involves guesswork, whereas the fixed charge option does not.

2. Staff's Position

Staff has not made policy or rate design recommendations regarding whether Rider VBA should be approved in these proceedings. Staff has, however, proposed a number of modifications to the rider in the event the Commission decides to approve decoupling for AIU. First, Staff recommends that the Commission incorporate the additional safeguards it approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff notes that AIU has agreed to modify Rider VBA to reflect any differences between the Rider VBA as filed in these proceedings and the Rider VBA approved in Docket Nos. 07-0241/07-0242 (Cons.). Staff does not take issue with the slight revisions to the proposed language addressing an annual internal audit of Rider VBA proposed by AIU.

Staff's second proposed modification involves a discussion of "full" versus "partial" decoupling. Staff witness Ebrey proposes that “full decoupling” be approved as a pilot program in this proceeding (if Rider VBA is to be approved) rather than the same program design that is already in pilot status for North Shore and Peoples, which is “partial decoupling.” She states that “full decoupling," as described in the NARUC document titled, “Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ)”, provided by AIU in response to AG data request 3.03d Attach (Staff Group Ex. 1), adjusts utility revenues for any deviation between expected and actual sales regardless of the reason for the deviation. Thus, Ms. Ebrey continues, it “decouples” revenues from any and all variations between actual operations and those predicted by the revenue requirement. Staff asserts that the variation of the full sales decoupling proposed by AIU is called “Sales-Margin Decoupling,” which separates margin recovery from sales by setting a margin-per-customer target. (Id.) Since the proposed AIU and approved North Shore and Peoples decoupling riders are both based on the same "partial” decoupling, Staff avers that it would not be logical to approve for AIU a program design identical to the one approved for North Shore and Peoples as a pilot program. The result would be three identical pilot programs; nothing would be gained from such an exercise. According to Staff, however, a Rider VBA program based on “full” decoupling as Staff proposes as a pilot program for AIU would provide the Commission with another alternative for comparison at the end of the pilot periods to determine which form of decoupling is preferable for Illinois utilities.

The third modification proposed by Staff concerns the adjustment calculation in Rider VBA to reflect “full" decoupling, should the Commission decide to approve the rider. Staff understands that the intent of Rider VBA is to assure dollar-for-dollar recovery of the portion of fixed costs currently recovered through the volumetric portion of delivery service charges. The proposed rider has an annual reconciliation mechanism which AIU says will only allow it to recover the Commission approved revenue requirements and not a dollar more. Staff, however, is not sure that the reconciliation mechanism can be relied upon to limit recovery to the approved revenue requirements.

In discussing its concern, Staff explains that Rider VBA has two main formulas: one to determine the Effective Component which calculates the Rider VBA charge to be applied to the Effective Month, and the other to determine the Reconciliation Adjustment for the annual true-up. The Effective Component formula calculates any over or under recovery of the fixed cost portion of the volumetric charges on a per customer basis as opposed to a total revenue requirement basis. Since any Commission-approved revenue requirement is based upon a projected number of customers, if AIU's actual number of customers exceeds that projected level, Staff indicates that there appears to be a possibility that AIU could collect more fixed costs through Rider VBA than approved in the revenue requirement. Specifically, AIU would collect more fixed costs from the additional customers‘ volumetric charges and from their monthly customer charges. Staff states that this would not be a concern if there were specific provisions in the proposed rider that would address this issue; however, there are none. Staff offers an example in its Initial Brief setting forth its concern. (Staff Initial Brief at 253)

Staff further explains that in approving the decoupling rider for North Shore and Peoples, it was implied that fixed costs are costs that are necessary to operate the utility regardless of any changes to the operation--a “fixed” cost of doing business regardless of the amount of business conducted. Converting the fixed costs to be recovered to a per customer basis suggests to Staff, however, that the costs are not truly fixed but that they will vary with the number of customers served. Staff contends that additional customers over the level assumed in the revenue requirement would not necessarily result in additional fixed costs to AIU. AIU claims that the “overwhelming majority” of its delivery system revenue requirements do not “vary” with the volume of natural gas consumed by customers and is thus “fixed” in nature. (AIU response to Staff data request TEE 15.05) In furtherance of this claim, AIU states that the only variable costs that the gas utilities have that are not recovered through the PGA clauses relate to odorant expense. (AIU response to Staff data request TEE 15.08) Staff points out, however, that AIU also claims, “Such statement is not intended to mean that [AIU] cost of service or revenue requirements are 'fixed' for any period of time.” (AIU response to Staff data request TEE 15.05) If costs vary based on any changes to the operations, including changes in the number of customers served, Staff believes that they can not be truly fixed costs. Staff contends that AIU has had the opportunity to provide support for how it defines “fixed” costs, clarify its statement that the costs under consideration are not fixed for any period of time, identify the total dollar amount of fixed costs it is seeking to recover in its proposed revenue requirement, and separately identify the portions of those fixed costs of service that it is seeking to recover from the customer charge and from the volumetric usage charge. Staff asserts that no such support has been provided in the record.

Implementation of Staff's third proposed revision to Rider VBA would first require AIU to identify those costs that are truly fixed. Modifying the Effective Component formula in the rider such that it is not calculated on a per customer basis but based on the total fixed cost component of the approved revenue requirement would follow. Specifically, Staff recommends that if the Commission approves Rider VBA that it modify the Effective Component formula as follows:

1. Effective Component

The adjustment, determined for each Rate, to be billed for the Effective Month is represented by the following formula:

[(RCBR ~~/ RCC~~) – (ABRR ~~/ AC~~)] ~~x RCC~~ / T x 100

Where:

RCBR represents the Rate Case Base Rate Revenue for the Reconciliation Month.

~~RCC represents the number of Rate Case Customers for the Reconciliation Month.~~

ABRR represents the Actual Base Rate Revenue for the Reconciliation Month.

~~AC represents the number of Actual Customers for the Reconciliation Month.~~

T represents the forecast Factor T for the Effective Month.

3. AG's Position

The AG argues that Rider VBA violates several critical ratemaking precepts and should be rejected. Setting aside the many legal infirmities of the proposed rider, the AG also argues that the evidence in no way demonstrates that a need for Rider VBA exists. Rider VBA, the AG asserts, would trigger piecemeal rate adjustments for isolated elements of utility revenue requirements in the absence of compelling evidence that such piecemeal rate adjustments are warranted.

A review of the AG's position begins with its observation that both the Act and Illinois court rulings regarding the utility ratemaking process provide an essential regulatory and legal framework for the Commission's analysis of Rider VBA. When the Commission enters upon a hearing to review a utility's proposed rate increase pursuant to Section 9-201 of the Act, it must determine whether the proposed rates are just and reasonable and do so within the regulatory parameters which prohibit retroactive and single-issue ratemaking. (See BPI II, 146 Ill.2d at 195) Following the discussion of the AG's legal analysis is a review of its policy arguments.

a. Legal Considerations

The AG raises several legal arguments against Rider VBA. The first argument concerns single-issue ratemaking. For utility ratemaking purposes, the AG states that riders are closely scrutinized because of the danger of single-issue ratemaking. (See City of Chicago v. Illinois Commerce Commission, 281 Ill.App.3d 617 (1st Dist. 1996)) The rule against single-issue ratemaking is a ratemaking principle which recognizes that the revenue requirement formula is designed to determine a utility's revenue requirement based on the utility's aggregate costs and demand. The rule prohibits the Commission from considering changes to components of the revenue requirement in isolation. As noted by the AG, limited exceptions to the rule against single-issue ratemaking exist. Based on the case law and statutory authorizations issued to date, the AG recounts that Commission decisions implementing riders for the recovery of certain expenses have not been reversed by Illinois courts as illegal single-issue ratemaking when the expenses at issue are (1) unexpected, volatile, or fluctuating, (2) imposed on the utility by law, including federal and state law (such as environmental clean-up expenses) and municipal ordinance for a unique purpose (such as franchise fees), or (3) specifically authorized by statute. The AG avers that fluctuations in gas usage within a customer class do not fall within one of these categories. In contrast, the AG believes that a rider focusing solely on such fluctuations without regard for all other circumstances is a prime example of single-issue ratemaking.

The AG's second legal argument is that Rider VBA contradicts ratemaking principles established by the U.S. Supreme Court. In the case Bluefield, the Court established that a utility's rates should reflect the opportunity – not a guarantee – to earn a return on its used and useful property when a commission sets rates. In spelling out the factors to be examined by regulators when establishing a utility's rate of return, the high court held that a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The Court further held that a utility has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. (Bluefield, 262 U.S. at 692-693) The Court specified that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. (Id. at 693) The Supreme Court also recognized that changes in the marketplace may impact a utility‘s financial health and the appropriateness of the rates being charged, when it held that a rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. (Id. at 692)

The AG observes that the U.S. Supreme Court elaborated on the principles governing rate of return regulation in the case of Hope. In Hope, the Supreme Court held that investors have a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. But in Market St. Ry. Co. v. Railroad Commission, 324 U.S. 548 (1945), the AG reports that the Court specifically rejected the notion that a monopoly must be protected from market realities, such as competition or the effects of price on a consumer‘s demand and use of the service. The Court explained, —Even monopolies must sell their services in a market where there is competition for the consumer‘s dollar and the price of a commodity affects its demand and use.” (Id. at 568)

Illinois courts have adopted the Bluefield and Hope standards and applied them to the regulation of utilities in Illinois. (See Illinois Bell Telephone Co. v. Illinois Commerce Commission, (1953), 414 Ill. 275) Moreover, the AG adds, Illinois appellate courts have declared that it is the ratepayers‘ interest which must come first:

> The Commission has the responsibility of balancing the right of the utility's investors to a fair rate of return against the right of the public that it pay no more than the reasonable value of the utility's services. While the rates allowed can never be so low as to be confiscatory, within this outer boundary, if the rightful expectations of the investor are not compatible with those of the consuming public, it is the latter which must prevail. (Camelot Utilities, Inc. v. Illinois Commerce Commission, 51 Ill.App.3d 5, 10, 365 N.E.2d 312 (1977), See also Citizens Utility Board v. Illinois Commerce Commission, 276 Ill.App.3d 730, 658 N.E.2d 1194 (1995))

These and the previously discussed holdings suggest, according to the AG, that AIU's request for the guaranteed recovery of the approved per customer —margin revenue” stream established when rates are set in this case through Rider VBA has no support in the utility regulatory law that has guided this Commission‘s establishment of rates.

The third legal argument made by the AG is that the circumstances at hand do not warrant the extraordinary regulatory treatment of a rider. In the case of A. Finkl & Sons Company v. Illinois Commerce Commission, 250 Ill.App.3d 317, 620 N.E.2d 1141 (1st Dist. 1993) (—Finkl”), the Illinois Appellate Court held that riders are useful in alleviating the burden imposed upon a utility in meeting *unexpected, volatile,* or *fluctuating* expenses. (Id. at 327) (emphasis in original) In addition, the AG observes that the court noted that the amount of costs to be recovered through the rider at issue in the case was not significant, and were recoverable through the usual rate case mechanism. The criteria enunciated in Finkl for determining whether a utility expense should be recovered through a rider was affirmed by the Illinois Supreme Court in Citizens Utility Board v. Illinois Commerce Commission, 166 Ill.2d 111, 651 N.E.2d 1089 (1995). While the Court upheld the Commission's approval of rider recovery of coal tar clean-up expenses in the case, it affirmed the criteria relied upon in Finkl for rider recovery of expenses, noting that the coal tar remediation expenses commonly incurred to comply with the mandate of federal and state law are sufficiently volatile and not within management's control to justify rider recovery.

In applying the Finkl standard to AIU's declining revenue situation, the AG examined the impact of Rider VBA had it been in place beginning in 2002. The AG reports that the largest annual margin dollar change would have been a margin revenue increase of $18.6 million in 2006. Although this amount is not insignificant, the AG asserts that it is not particularly large in relation to the total test year operating income of $272 million proposed by AIU in this proceeding. The AG does not consider this amount large enough to warrant rider treatment under Finkl. Nor does the AG believe that historical fluctuations in gas usage due to weather count as unacceptable levels of volatility under Finkl. The AG also suggests that AIU management has some control over usage in light of AIU witness Nelson's comments regarding energy efficiency programs.

The fourth legal argument raised by the AG concerns the Act's requirement in Sections 1-102 and 8-401 that utility rates be least-cost. The AG contends that implementation of Rider VBA will permit piecemeal rate increases that violate this requirement. Had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional $38.8 million in gas delivery charges. If AIU's predictions about declining gas usage per customer are correct, the AG states that Rider VBA's monthly adjustment of customer rates will not produce rates that are —least-cost," as required by the Act.

The AG's fifth argument is that Finkl prohibits recovery of revenues lost due to energy efficiency and conservation efforts. In Finkl, the AG reports that the appellate court flatly rejected the notion of making a utility whole for lost revenues associated with conservation or demand side management programs. Given the parallels between the rider at issue in Finkl and Rider VBA, the AG contends that implementation of Rider VBA would be illegal.

The sixth legal argument is that Rider VBA violates the Act's prohibition against discrimination in rates. Section 9-241 of the Act prohibits any utility from establishing or maintaining any unreasonable difference in rates or other charges between customer classes. AIU seeks to maintain a designated level of revenues per customer on a monthly basis after rates are set in this proceeding for residential and small commercial classes, but not for the other rate classes served by AIU. Although AIU argues that a decoupling rider is needed because declines in usage per customer cause a significant under recovery in the fixed cost of service and an inability to earn authorized returns, the AG asserts that nowhere in any AIU witness' testimony does there exist evidence that decreases in usage per customer are limited to residential and small commercial customers. Nevertheless, Rider VBA does not apply to other customer classes. Therefore, according to the AG, Rider VBA constitutes unreasonable discrimination against residential and small commercial customers. The AG avers that adjusting the monthly charges to these customer classes, based on changes in future gas usage (and the margin revenues produced), from the baseline level of revenues per customer established in this case, but not for AIU's other customer classes, contradicts the prohibition in Section 9-241 against unreasonable discrimination between customer classes.

b. Policy Considerations

A part of any rate case, the AG relays, is the ―matching principle," which recognizes the importance of matching within the test year all revenues and costs (expenses, rate base, rate of return) to determine needed changes in utility service pricing. As long as revenues and costs remain in approximate balance, causing a utility‘s earnings to stay within acceptable proximity to authorized return levels, the utility may be able to go many years between rate cases. The fundamental problem with riders, the AG argues, is the potentially serious distortion of the matching principle under traditional ratemaking that occurs when a single expense item is tracked in isolation, thereby ignoring other changes occurring to expenses and revenues that affect a utility‘s revenue requirement.

A related concern of the AG is that implementation of any rider focusing on a single expense item will eliminate or reduce the incentive for utility management to control and reduce costs. Because rates are typically fixed for a period of years, the AG asserts that the regulatory lag that occurs provides utility management with efficiency incentives and symmetrical risks and opportunities for both ratepayers and shareholders -- depending on cost and revenue trends -- between rate cases. The AG notes that regulatory lag has worked out well for AmerenCILCO's gas operations, which AIU admits is currently over earning. Another advantage of traditional test year ratemaking over riders identified by the AG is the intensive focus upon utility operations and costs that occurs in a rate case in which Staff and other interested parties can carefully examine the components making up the revenue requirement.

In addition to the reduction in management incentives (resulting from eliminating regulatory lag), AG/CUB witness Brosch identifies other concerns stemming from rider recovery of certain rate elements:

- Shifting of cost responsibility and risk to customers who are least able to influence cost levels or sales levels;

- Increases in tariff and bill complexity that may be difficult to explain to customers or that may complicate customers‘ ability to control their costs;
- Administrative complexity and additional costs associated with audit verification and administration of complex accounting entries, cost allocations and/or tariff calculations, often on an accelerated procedural schedule; and
- Potential for inadequate regulatory oversight and auditing of rider tariffs.

Given the importance of the matching principle in traditional ratemaking and the potential problems inherent in rider recovery of rate elements, the AG contends that exceptions to normal test year ratemaking should only be allowed when extraordinary circumstances exist that preclude the setting of just and reasonable rates through the traditional test year process. The AG maintains that there has been no showing by AIU of any extraordinary circumstances sufficient to justify departing from the continued balanced regulation of future changes in AIU's costs and revenues via periodic rate cases.

Mr. Brosch testifies that costs or revenue changes to be tracked through a rider should generally have *all* of the following characteristics to merit the exceptional and preferential treatment inherent in riders:

- Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases;
- Beyond the control of management, where utility management has little influence over experienced revenue or cost levels;
- Volatile in amount, causing significant swings in income and cash flows if not tracked;
- Straightforward and simple to administer, readily audited and verified through expedited regulatory reviews; and
- Balanced, such that any known factors that mitigate cost impacts are accounted for in a manner that preserves test year matching principles.

The AG asserts that it is no coincidence that the general criteria for rider treatment that are cited and discussed by Mr. Brosch are closely aligned with the factors considered and adopted in the Commission and Illinois court cases cited above. The AG maintains that AIU has failed to make a case that extraordinary rider treatment of revenues lost due to declines in usage per customer is needed from a financial perspective in order for AIU to have a reasonable opportunity to achieve a fair return on investment.

The arguments that AIU has made in support of Rider VBA are meaningless red herrings in the AG's view. In response to AIU's claim that full recovery of fixed costs is at risk because a portion is based on volumetric charges, the AG counters that AIU fails to acknowledge that the Commission sets rates after considering normal weather and the estimated number of bills that a utility expects to issue. Focusing on margin revenues per customer, the AG continues, also ignores the fact that AIU's revenue streams and expenses are dynamic. For instance, revenue from new customers may compensate for existing customers' decreased usage. Improvements in productivity can also reduce expenses to compensate for existing customers' decreased usage.

The AG states further that under AIU‘s ratemaking paradigm a natural gas delivery utility should be made whole for all per customer load losses, no matter whether the decline in usage is due to conservation efforts, customers‘ desire to dial down the thermostat and reduce winter heating bills in response to high gas prices, or the prevalence and installation of more efficient appliances. Moreover, according to the AG, AIU witness Cooper confirmed that as customers increase their efforts to conserve natural gas, their delivery service rates will increase. (Tr. at 539-540) The AG is troubled that the amount of natural gas service used by a customer becomes irrelevant to the amount of money owed to the utility for gas delivery service. When usage per customer declines, AIU generally and theoretically asserts that its overall revenues and profits decline and its cost of service is not fully recovered. Even when revenues collected from new customers offset the impact of reduced usage by existing customers so that there is no loss in overall revenues, the AG understands that a surcharge may nonetheless be imposed on residential and small commercial customer bills under Rider VBA. Similarly, the AG also understands that even if total revenues exceed the level approved in this rate case, a surcharge will be imposed if use per customer declines.

Conspicuously absent from the record, the AG avers, is any evidence that overall margin revenues have dropped precipitously or become unstable in the years since AIU's last gas rate case so as to justify the unorthodox ratemaking treatment that Rider VBA brings. Moreover, the AG states that AIU provided no attrition studies or estimates of any kind showing margin revenue losses that will occur in the future that suggest that it will be unable to earn its authorized return after the entry of the rate orders in this proceeding or that justify the approval of Rider VBA. In fact, the AG points out, gas usage per customer has been declining for decades, yet AIU has been able to operate under the traditional rate making approach without decoupling. Rejecting Rider VBA will not harm AIU, the AG observes, because when under-recovery does occur the traditional rate case filing process is still available to AIU. Additionally, as noted above, had Rider VBA been in effect from 2004 through 2006, the AG reports that AIU would have collected an additional $38.8 million in gas delivery charges--a cumulative impact of about 7.1% of overall margin revenues in those years. The AG asserts that this would have been an unjust windfall to AIU since the traditional rate case process would have protected AIU's interests.

The AG does not accept AIU's argument that Rider VBA is necessary to remove any disincentive to promote energy efficiency. First, the AG points out that AIU has no history of providing energy efficiency programs or assessing their effect on customer usage. Given this lack of experience, the AG claims that the discussion regarding the alleged disincentive to promote efficiency rings hallow. Second, the AG notes that AIU has no plans for energy efficiency programs beyond the $6.5 million program at issue in Docket No. 08-0104. While AIU asserts that implementation of that program is contingent upon approval of Rider VBA, the AG observes that AIU witness Nelson acknowledges that the Commission can direct AIU to provide the program without Rider

VBA. Third, the AG maintains that Rider VBA may actually discourage customers from increasing the efficiency of their home or business or otherwise reduce their gas usage if their total bill is less dependent on the amount of gas they use. The AG finds AIU's concerns about promoting efficiency particularly specious when one considers that AIU is only seeking decoupling for its gas operations. As Mr. Nelson explains in his response to AG 3.03(c) (MLB), "average electric sales per customer are not declining. Implementing a decoupling mechanism for the electricity business likely would have the effect of providing [AIU] with less revenue over time, and would hasten the need for a subsequent rate case--neither of which is in the interests of [AIU] or its customers." (AG Initial Brief at 43) Thus, the AG concludes that AIU is apparently proposing only gas decoupling in furtherance of the simple financial goal of collecting the maximum revenue between rate cases for the benefit of shareholders--and not due to any altruistic motivation to remove disincentives to promoting energy efficiency.

The AG is also concerned by the additional administrative burdens that approval of Rider VBA will bring. According to the AG, Mr. Brosch and Staff witness Lazare both express concerns about the additional burden that review of three additional riders, and the three annual rates of return reports, will impose on all parties. The AG is not persuaded by AIU's assurances that Rider VBA reconciliations will be simple and uncontroversial.

4. CUB's Position

CUB objects to Rider VBA and relies on Bluefield, Hope, and Finkl in the same manner as the AG. CUB also discusses the arguments of Mr. Brosch. CUB spent additional time, however, discussing BPI II. In BPI II, the Illinois Supreme Court described the rule against single-issue ratemaking as recognizing that the revenue formula is designed to determine the revenue requirement based on the aggregate costs and demand of the utility. Therefore, it would be improper to consider changes to components of the revenue requirement in isolation. Often times a change in one item of the revenue formula is offset by a corresponding change in another component of the formula. To demonstrate this point, CUB states that an increase in depreciation expense attributable to a new plant may be offset by a decrease in the cost of labor due to increased productivity, or by increased demand for electricity. (CUB explains that demand for electricity affects the revenue requirement indirectly. The yearly revenue requirement is divided by the expected demand for electricity to arrive at a per kilowatt-hour ("kWh") rate. If actual demand is more than the estimated demand used in the formula, the utility's revenues increase.) In such a case, CUB states that the revenue requirement would be overstated if rates were increased based solely on the higher depreciation expense without first considering changes to other elements of the revenue formula. Conversely the revenue requirement would be understated if rates were reduced based on the higher demand data without considering the effects of higher expenses. (See BPI II, 146 Ill. 2d at 244-45) The exception permitting recovery of costs outside of the traditional rate-setting process is recovery through riders.

Riders allow a utility to collect revenues associated with a particular cost as it is incurred, without waiting until it files a general rate case to recover such expenses. CUB quickly points out, however, that rider cost recovery is only permitted under limited circumstances, as discussed in Finkl. In this instance, CUB does not believe that it is appropriate to make up for declining revenues, due to decreased gas usage, through a rider. CUB maintains that the proposed Rider VBA is beset by many problems. First, CUB is not convinced that Rider VBA is necessary and notes that AmerenCILCO's gas operation is over-earning despite declining gas usage by customers. CUB adds that fluctuation in earning is common between rate cases and that regulatory lag can even work to a utility's advantage, as it is currently for AmerenCILCO. When earnings are consistently low, CUB asserts that the proper course of action is to file for a rate increase.

CUB is also troubled by AIU witness Cooper's assertion that, rather than reviewing its proposed rates under the standards articulated in Article IX of the Act regarding just and reasonable rates, the Commission should consider that ―the real metric for determining whether the tariffs for a utility are just and reasonable is a comparison between the margin revenues generated by these tariffs versus the margin revenue requirement necessary for the utility to have a reasonable opportunity to earn its Commission authorized rate of return.” (Ameren Ex. 25.0 at 7) He further argues that the current rate structure has not resulted in earning the respective authorized rates of return. CUB contends that this argument invents a new standard of review – the ―margin revenue requirement” – that belies the Act and well-established regulatory policies and principles. CUB believes that it is important to note that, while the Commission always establishes a revenue requirement level, it measures a utility‘s performance by whether it is meeting its approved rate of return. In fact, CUB continues, the Commission up to this point has never approved a specific level of margin revenues or margin revenue requirement for any gas utility in Illinois.

CUB takes no solace in AIU's willingness to modify Rider VBA so that it more closely resembles the Rider VBA approved in the Docket Nos. 07-0241 and 07-0242 (Cons.). First, CUB argues that calling the rider a "pilot," while simultaneously subjecting all residential customers to potentially higher delivery rates for four years, without substantial review of the program, does nothing to improve it. Second, Mr. Brosch testifies that the annual rate of return filings are no substitute for a correctly structured formula that accounts for all related costs and revenue changes between test years, and are virtually useless in determining whether the riders have caused AIU to earn returns in excess of those authorized by the Commission. Third, since a majority of the delivery system costs are fixed, CUB states that ensuring that only the utility‘s fixed costs are reflected in the volumetric delivery charge and the associated Rider VBA surcharge will have little to no effect on the level of surcharges imposed under Rider VBA.[10]

[10] The Commission does not mean to slight CUB or diminish the worth of CUB's arguments by not addressing all of CUB's arguments in the Commission's review of CUB's position. Rather, given the similarities between CUB's position and the AG's position, the Commission simply does not believe that repetition of such similar arguments in the Order is warranted.

If it were the Commission's goal to provide utilities with guaranteed cost recovery of its fixed costs, CUB asserts that that policy would more appropriately dictate establishing recovery of all fixed delivery costs through the application of a fixed monthly charge to all affected customers. While CUB acknowledges AIU's suggestion that increasing the monthly customer charge is an alternative to its decoupling proposal, CUB opines that AIU is not seriously proposing to increase the monthly charge. If in fact that is what AIU is proposing, CUB contends that it would likely be rejected outright by this Commission as violating basic ratemaking principles like avoidance of rate shock, maintaining fair and equitable rates, and other cost of service principles. According to CUB, Dr. James Bonbright, an authority on utility ratemaking, has called into the question the propriety of uniform customer charges. CUB quotes Dr. Bonbright as saying, ―uniformity of charge per customer (say, $10 per month for any desired quantity of service) has charm in avoiding metering costs. Nevertheless, it is soon rejected because of its utter failure to recognize either cost differences or value-of-service differences between large and small customers." James C. Bonbright et al., "Principles of Public Utility Rates," at 397 (1988).

5. IIEC's Position

From IIEC's perspective, and from a general customer perspective, riders are objectionable and should not be approved when the riders: (a) inappropriately shift operating risk from the utility to customers, as when the costs of service at issue are fully capable of base rate recovery, (b) adjust rates on the basis of only selected costs elements without considering other (possibly offsetting) costs, revenue changes, or other factors that affect the utility's overall profitability (also known as single-issue ratemaking), (c) distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process, or (d) create cross-subsidies or otherwise result in unfair cost recovery. Because Rider VBA falls short of these criteria, IIEC opposes its implementation.

IIEC asserts that the current regulatory framework provides all interested parties with a fair opportunity to review all items affecting cost-based rates. At the same time, IIEC continues, the existing regulatory framework provides utilities an opportunity to earn a fair return. With Rider VBA, IIEC argues that AIU is inappropriately attempting to shift the risk of non-recovery of anticipated revenues to customers. Currently, AIU's shareholders bear the risk that earnings could be adversely affected between base rate cases due to increases in costs or a reduction in revenue. Conversely, AIU's shareholders benefit if the AIU gas utilities can successfully reduce costs or increase revenues between rate cases. IIEC contends that these facts create a powerful incentive for AIU to operate cost-effectively and to promote economic development efforts in its service areas, increasing revenues, and improving AIU's bottom line between base rate cases. IIEC states that Rider VBA would essentially make AIU indifferent to the impact of fluctuations in sales levels in the service areas, eliminating this incentive.

6. AARP's Position

AARP opposes implementation of Rider VBA. While AIU claims that it "needs" this rider, AARP states that AIU has not provided an analysis of whether overall gas revenues are increasing. As illustrated by AG/CUB witness Brosch, AARP reports that AIU's actual margin revenues have been relatively stable over the past 13 years, in spite of weather fluctuations and in spite of a supposed downward trend in usage. AARP states further that the addition of new customers has historically served to offset most or all of the declining usage per customer noted by AIU. AARP concludes that there is no need for this piecemeal Rider VBA (which would not simultaneously recognize increases in customer numbers) based upon the evidence in the record of this case.

Despite the fact that AIU emphasizes that this rider would be —symmetrical,” AARP argues that it would clearly tip the regulatory scales against consumers and grant an almost guarantee to the utility‘s margin revenues. Mr. Brosch argues that specific margin revenues should not be guaranteed. Such guarantees, AARP contends, fundamentally undermine the entire premise of rate of return regulation, forcing consumers to pay the utility a rate of return while shifting the risks of doing business onto those same consumers. AARP reports that calculations show that based on historical records, AIU would have collected an additional $38.8 million in gas delivery charges from consumers from 2004 through 2006, a cumulative impact of 7.1% of overall margin revenues over that period of time.

Not only is the Rider VBA a piecemeal approach as to the rate of return formula for ratemaking, AARP notes that AIU's proposal is piecemeal as to its overall operations in that it is being proposed for its gas operations, but not its electric operations. AARP relates that the reason given by AIU was that electric sales per customer are not currently declining, and thus an electric decoupling rider would likely produce less revenue for AIU. AARP avers that such a response clarifies that the utility‘s goal is actually revenue enhancement, not the removal of any —disincentive” regarding energy efficiency programs.

Furthermore, AARP suggests that the Commission should not embark upon another new decoupling pilot program, at least not until the People‘s Gas decoupling rider (just approved on February 5, 2008) is allowed to run its course and is then evaluated. Launching straight into another similar —pilot” may satisfy some sense of uniformity between regulated utilities, but according to AARP it would be to the detriment of yet another group of consumers without any proof that this specific utility truly —needs” such a mechanism. If a pilot program is to mean anything, AARP asserts that it should at least be used as an experiment to test the necessity for such extraordinary mechanisms and to analyze how much more ratepayers actually wind up paying.

Moreover, AARP continues, the Commission may learn from the People‘s Gas pilot what unintended customer reactions may develop when the benefits of conservation are taken away from natural gas consumers. AIU discusses how Rider VBA would reduce its —disincentive” to support energy efficiency efforts, but according to AARP it did not discuss what impact the Rider VBA would have on customer behavior. Mr. Brosch concludes that Rider VBA will likely diminish the incentive for consumers to lower their thermostats, invest in energy efficient appliances and weatherization, or to participate in the very programs that AIU claims it wants to provide. AARP believes that many of its members will likely feel discouraged from engaging in conservation, knowing that any overall gains in conservation would be quickly diminished by the operation of this rider.

7. Commission Conclusion

Rider VBA as proposed only applies to GDS-1 and GDS-2 customers of each gas utility. The Commission therefore understands that AIU is most concerned about declining gas usage by these two customer classes. Of the fixed delivery service costs recovered through customer charges, volumetric delivery charges, and demand charges, AIU indicates that approximately 43% of its fixed delivery service cost is recovered based on the volume of gas used by customers. The vast majority of the remaining fixed delivery service costs are recovered through the monthly customer charge. Whenever gas usage by these two classes falls below the test year usage level, AIU's ability to recover that portion of its fixed costs collected through the volumetric charge is impaired.

Why AIU would want to recover as much of its authorized revenue requirement as possible is clear. AIU has proposed Rider VBA as a means of recovering its fixed costs through the continued use of volumetric charges. In Docket Nos. 07-0241 and 07-0242 (Cons.), the Commission recently approved the use of a similar rider for Peoples and North Shore as a four year pilot program. From this decision, it is evident that the Commission is willing to consider alternatives to the traditional method of recovering a portion of fixed costs through the volume based portion of the bill.

The Commission is fully aware that its decision in Docket Nos. 07-0241 and 07-0242 (Cons.) was controversial. Many of the same parties involved in that proceeding have participated in this proceeding and made many of the same arguments regarding AIU's proposed Rider VBA. The Commission acknowledges those concerns and reevaluated them in this proceeding.

What carries the most weight is the argument that the Peoples/North Shore Rider VBA was approved as a pilot program, and it would make little sense to expand the pilot program to AIU without having any of the results from Peoples' and North Shore's experience. AIU's proposed Rider VBA is very similar, if not substantively identical, to the Rider VBA approved in Docket Nos. 07-0241 and 07-0242 (Cons.). If there are unknown flaws in the approved rider, it is likely that the same flaws exist in AIU's proposed rider. Allowing Peoples and North Shore to implement this controversial rider under the pilot program, and hopefully identify any problems with the rider, before expanding it to a significant number of additional customers seems more prudent than expanding the rider now without the benefit of any significant experience with the rider. Furthermore, using an alternative to Rider VBA that would still provide AIU a better opportunity to recover its fixed costs will supply the Commission more information with which to evaluate ways to recover a utility's fixed costs.

An alternative to Rider VBA that would still promote fixed cost recovery by the utility is recovery of a greater portion of fixed delivery costs through the fixed monthly charge to all affected customers. AIU makes this suggestion and notes that under this method, utilities could not over- or under-recover their Commission-approved base rate revenue requirement with changes in sales. AIU adds that this alternative would also send proper price signals to customers. The Commission concurs with these statements and notes further that this alternative arguably decreases any disincentive AIU may perceive to implementing gas efficiency programs. Specifically, AIU has pending before the Commission in Docket No. 08-0104 a gas energy efficiency plan which it indicates is contingent upon approval of Rider VBA. The Commission anticipates that in light of the end result under the conclusion on this issue, AIU will not shy away from efforts to decrease gas consumption by its customers.

Accordingly, the Commission concludes that it will not adopt AIU's Rider VBA, but that it will direct AIU to increase its monthly customer charge for the GDS-1 and GDS-2 classes to recover more of its fixed delivery services costs. AIU proposes a monthly charge of $15.00 for all GDS-1 customers. AmerenCILCO's current monthly residential customer charge is $11.80. The current monthly charge for AmerenCIPS Metro-East residential customers is $15.00. For all other AmerenCIPS residential customers, the monthly charge is currently $10.50. The standard monthly charge for AmerenIP residential customers is currently $10.27, while the non-standard monthly charge is $32.46. The current and proposed monthly customer charges for small general service under GDS-2 vary depending on meter facilities and whether a customer is a sales or transportation customer. Ameren Ex. 12.2G identifies the current and proposed monthly charges. As mentioned earlier, AIU's proposed monthly customer charges for GDS-1 and GDS-2 customers would recover nearly 57% of AIU's proposed fixed delivery services costs. AIU should modify its monthly customer charges for these classes to recover 80% of the fixed delivery services costs approved in this proceeding. With regard to varying charges for the GDS-2 class, the increases should be proportionate to existing rates. The Commission anticipates that this method of recovering fixed delivery costs will be simpler and easier for customers to understand than Rider VBA.

The Commission does not at this time approve recovery of all fixed costs in the monthly charges for two reasons. First, it is expected that leaving a portion of fixed costs to be recovered through the volumetric rate will encourage AIU to seek ways to improve efficiency and otherwise cut costs. Second, as the number of AIU's customers grows, AIU should experience growing revenue. If all of its fixed costs were recovered through the monthly charge, AIU may arguably over-recover its fixed costs through the monthly charge.

In order to gain sufficient experience to evaluate this method of recovering fixed delivery costs, the Commission anticipates that the approved ratio of fixed costs recovered from the customer charge and the volumetric rate must remain in place until at least December 31, 2012. AIU may propose revisions to this ratio in its next rate case or rate design case thereafter. By this time the Commission should also have the benefit of Peoples' and North Shore's experience with Rider VBA.

In their respective Brief on Exceptions, Staff and the AG complain that increasing the monthly customer charge to recover a greater portion of fixed costs will be detrimental to GDS-1 and GDS-2 customers. While the Commission acknowledges that the monthly charges will increase and such increases may be more apparent on bills than changes to volumetric rates, the fact remains that the volumetric rates will decrease by a corresponding amount. Therefore, on average, there should be no overall adverse revenue impact on customers resulting from recovering a greater portion of fixed costs through the monthly customer charge than a volume based rate. So that customers realize this, however, the Commission directs AIU to include in at least one bill insert soon after entry of this Order a statement explaining that a greater portion of the fixed costs of delivering gas will be recovered through the monthly customer charge and that the amount of fixed costs recovered through the volumetric charge has been correspondingly reduced.

B. Rider QIP

1. AIU's Position

AIU states that it intends to improve infrastructure performance (i.e., system reliability) by increasing both O&M expenditures and capital expenditures. Specifically, AIU states that it plans to spend $909 million in electric capital expenditures for the 2007-2009 time period. Over two-thirds of these capital expenditures, AIU continues, will be dedicated to infrastructure improvement.

Certain factors, however, limit its ability to make infrastructure investments, according to AIU. Obviously, access to capital funds is necessary. AIU explains that some of those funds are provided by cash flow from operations, based on the revenue requirement and rate base from the most recent rate case. AIU claims, however, that cash flow from operations will be insufficient to make such improvements based on a static rate base and revenue requirement. AIU says that it will therefore have to go to the capital markets to secure funds for infrastructure investments. Without a ready source of rate recovery for capital investments, AIU states further that there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors. In other words, AIU is asserting that significant and continued investments in infrastructure can only be made, and sustained, when a fair return on and a return of investment are received on a timely basis. AIU adds that capital investments made between rate cases cause earnings and return on equity to fall, further impairing the ability to raise capital.

AIU indicates that it can address the regulatory lag issue in one of two ways: (1) delay projects so they are timed with a rate case; or (2) create a rate mechanism to reflect such incremental projects in rates on an on-going basis, subject to Commission review and reconciliation. AIU proposes the incremental approach, which includes the capital costs of projects in rates as they are completed and placed into service. Thus, AIU is seeking approval of Rider QIP to provide timely recovery of capital costs for certain distribution plant investments, thereby allowing continued investment in infrastructure. The rider would recover costs associated with a defined set of plant additions beginning after December 31, 2007.

AIU proposes to limit the project expenses recoverable under Rider QIP. For example, capitalized expenditures related to existing distribution plant would qualify for the rider. Plant additions associated with new customers would not qualify for the rider, because those projects would produce additional revenue. AIU explains that these criteria are consistent with its goal to make its system stronger and more durable because capital expenditures on existing distribution plant are made to either enhance the system or replace existing plant to increase system reliability.

Customers will benefit from the projects eligible for Rider QIP cost recovery, according to AIU, through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced. AIU indicates that these are not the only types of system improvements that could benefit customers. Additionally, AIU states that investments may be required as a result of the Commission-mandated audit of AIU's delivery systems and storm preparedness when recommendations are received in 2008. AIU states further that it is studying ―smart metering" and ―smart grid" technologies that may provide future benefits to customers.

The concepts of smart metering and smart grid are currently being defined as the transformation of the electric delivery system of the 20th century into the delivery system of the 21st century. Many envision the system of the future as one that will continue to use the same types of equipment that are used today for electric delivery – e.g., power lines, substations, and transformers − but also picture it as a fully automated delivery network that monitors and controls every customer and node, ensuring a more reliable flow of electricity and a two-way flow information between the power plant and the appliance, and all points in between. AIU reports that smart metering, in addition to measuring electricity usage and voltage on a real-time basis, allows for two-way communication and provides the utility with new capabilities for operating and managing the delivery system. Smart metering coupled with communication functionality could enable utility customers to see and understand how and when they consume electricity. This in turn, AIU continues, will provide consumers the ability to manage their consumption of energy and take advantage of time-based rates − shifting usage of energy from peak periods or high-cost periods, taking steps to conserve electricity, and reducing their energy costs.

Furthermore, while smart meters will satisfy traditional metering needs for the utility − the measuring of the consumption of energy for system design and billing purposes - they could also serve as portals into the consumers' homes or businesses. AIU contends that smart meters will add additional value for both the consumer and the utility when the information they provide and the communication capabilities are used to enable distribution automation, demand response, load management, and real-time pricing. As the electric delivery system or grid continues to evolve, AIU submits that smart meters could become an integral part of an array of intelligent electronic devices that will make up what is conceptually referred to now as the —smart grid."

AIU indicates that it has already invested in advanced meter reading ("AMR") technologies--beginning a 4-year deployment of automated meter reading technology in May, 2006. AIU states that its commitment to the deployment of AMR technologies has required and will continue to require a significant investment in new and retrofitted meters, data gathering equipment, and telecommunications and information processing systems. Benefits that AIU anticipates deriving from AMR technologies include, but are not limited to, reduced meter reading costs, improved reliability, and enhanced restoration efforts through remote detection of customer outages.

In addition to implementing some level of AMR technologies, AIU states that it intends to begin studying the costs, benefits, and steps that would be necessary to implement smart meters and the smart grid for residential and small commercial customers. As of this year, AIU has begun assessing and comparing the current state of the energy infrastructure in the region to future scenarios involving smart grid technologies. AIU also plans to identify additional programs and potential tariff offerings that would allow customers to begin to take advantage of some of the benefits of smart metering. AIU argues that Rider QIP would facilitate investments in smart metering and a smart grid.

In an effort to address some of the concerns expressed by Staff and interveners, AIU modified its original Rider QIP proposal. In particular, AIU proposes to change the definition of Rider QIP projects to include only those associated with system modernization or service reliability enhancements. Further, before any project costs can be recovered through Rider QIP, AIU says that it will file a cost/benefit analysis. AIU has committed to make any such filing on or before April 1st of each applicable calendar year, providing nine months to review and approve any Rider QIP charges prior to the subsequent January 1 effective date. Parties could intervene in a Commission proceeding initiated after the filing of a cost/benefit analysis and express their views on which projects or initiatives, if any, should qualify for rider recovery. The Commission would then decide which projects or initiatives qualify.

AIU believes that the cost/benefit analysis should also address the concerns of the AG, IIEC, and AARP regarding the shifting of risk to customers and loss of incentives for the utility to behave in a prudent manner if Rider QIP is approved. AIU argues that these claims should be disregarded since passing a cost/benefit test at the Commission must precede timely recovery of the costs associated with a project. This process, AIU continues, results in maintaining the status quo, especially in times of escalating costs. Moreover, AIU states that each utility is still bound thereafter to justify the prudence of the expenditures actually made in an annual prudence review. AIU asserts that it has every reason to behave in a manner that ensures that the Commission will not disallow costs. To mitigate the impact of reviewing Rider QIP on the Commission‘s resources, AIU offers to pay a combined $100,000 annual filing fee. Concerning operational risk, AIU insists that Rider QIP does not shift operating risk; instead, it neutralizes operating risk.

AIU acknowledges AG/CUB witness Brosch's concern that Rider QIP does not take into consideration updates to the depreciation reserve, deferred taxes, and O&M expense. He also states that Rider QIP does not consider potential savings related to new plant investment. To address such concerns, AIU will be filing an annual rate of return report along with each Rider QIP filing to the extent that the subject costs are being recovered through the rider. The annual rate of return report will contain updated depreciation reserves, deferred taxes, and O&M expenses, which the Commission may consider when evaluating whether or not to allow Rider QIP recovery. AIU indicates that if the Commission determines that AIU is exceeding the allowed return, or if it believes potential savings, if any, from a project or initiative will cause AIU to exceed the allowed return, the Commission can choose not to allow Rider QIP recovery. Additionally, AIU agrees that Rider QIP can stand as a pilot program through and including December 31, 2012. Thereafter, AIU would need to re-file Rider QIP or some variation of the rider if they seek to continue to recover costs in such a manner.

Staff witness Lazare's suggestion that AIU use a future test year to recover anticipated project costs does not sway AIU. AIU claims that a future test year does not adequately address its concerns regarding regulatory uncertainty. AIU states further that a future test year is difficult to prepare and both costly and burdensome.

AIU does not oppose Staff witness Stoller‘s recommendation that the Commission take up this type of rider in a broader proceeding, outside of a rate case. AIU states that the Commission should give serious consideration to initiating a proceeding to examine what it claims are "evolving" service quality standards. But at the present, AIU is willing to make Rider QIP a pilot program now, with a definite expiration date. AIU believes that the expiration date should address Mr. Stoller‘s concern since it allows the Commission to consider a permanent program or rule in a broader proceeding, while allowing Rider QIP to go into effect in the meantime.

In response to Mr. Brosch and IIEC witness Stephens arguing that the infrastructure project costs are predictable and controllable and therefore do not warrant rider treatment, AIU contends that there needs to be recognition of changing times and public policy. AIU points out that in the Rate Relief Bill (Public Act 95-0481) passed last summer, there was recognition that the State, through electric utilities, would pursue energy efficiency and demand response programs and technologies. As part of that policy, the General Assembly authorized the use of an automatic adjustment clause rider to be approved by the Commission to recover the subject costs. Similarly, AIU continues, the General Assembly in late 2006 passed legislation mandating residential real time pricing. A rider was also authorized that would allow the utility to recover its costs. AIU recognizes that these are legislatively mandated riders, but reasons that the Commission is an extension of the General Assembly and is fully capable of promoting public policies as well.

Mr. Stephens speaks of the opportunity for the utility to enhance cost recovery in between rate cases, as does AARP witness Smith. AIU contends that a utility may have been more opportunistic in between rate cases when it owned generation, when increased load growth, off-system sales, or hot summers would have increased revenue. Today, however, AIU maintains that a utility without generation does not experience the same benefits as a generation-owning utility that would allow it to absorb the lag associated with significant delivery investment without adversely affecting earnings. Similarly, AIU does not accept Mr. Smith's claim of increased revenues between rate cases since AIU contends that costs will continue to escalate.

2. Staff's Position

Staff recommends that the Commission reject AIU's proposed Rider QIP as it represents a deviation from traditional regulation that would add significant costs for ratepayers and to the regulatory process without providing any tangible benefits. Staff acknowledges that AIU anticipates capital expenditures of $909 million for its electric systems over the 2007-2009 time period. Staff also understands that AIU is concerned about the regulatory lag associated with recovering these costs through the traditional rate case process. AIU's arguments in support of Rider QIP, however, do not sway Staff. Staff points out that rider recovery should be reserved for highly volatile, uncontrollable, and/or unpredictable costs--a standard which even AIU recognizes. Yet none of AIU's arguments, Staff notes, suggest that these costs are volatile, uncontrollable, or unpredictable.

If AIU expects to incur significant costs in the future, Staff suggests that a more reasonable approach would be to file a rate case based on a future test year. A future test year could be designed to recover future investments that may not be appropriately captured in an historical test year. In response to AIU's concerns that a future test year is difficult to prepare, costly, burdensome, and rarely used, Staff identifies three pending rate cases using future test years: Docket No. 07-0507 (IAWC), Docket Nos. 07-0620, 07-0621, and 08-0067 (Cons.) (Aqua), and Docket No. 08-0363 (Nicor). If smaller water utilities have the capability of employing future test years, it is not clear to Staff why AIU should find a future test year prohibitively difficult to prepare or too costly and burdensome to implement. Staff asserts that AIU's concerns about regulatory uncertainty should be dismissed as well. Staff avers that the requirement that reasonable justification for system upgrades be provided in the ratemaking process is essential to protect the interests of shareholders and ratepayers alike. Furthermore, Staff states that AIU can reduce regulatory uncertainty by providing strong support for the proposed investments.

Staff also understands that AIU is considering smart metering and smart grid technologies. The problem that Staff has with AIU's interest in such technology is that it is not clear whether Rider QIP is being proposed to make the system more reliable, to transform it technologically, or to do both. The fact that the language of the rider and AIU witness Nelson‘s discussion of smart meters and the smart grid are both open-ended raises a concern for Staff that approval of Rider QIP will give AIU a license to transform the distribution system beyond the ability of ratepayers to pay the corresponding costs. As the events of 2007 clearly indicate, the concerns of ratepayers appear to be with the levels of their electric bills.

In response to Mr. Nelson's claim that customers would not pay any more for reliable service under Rider QIP, Staff argues that the reality would be the opposite. In between rate cases, Staff asserts that AIU would be able collect additional amounts from customers, which contrasts with traditional ratemaking where utilities can not pass along additional costs once rates are set. Moreover, Staff contends that AIU fails to provide adequate reason why ratepayers should be asked to pay an extraordinary price for what appears to be ordinary electric service. Mr. Nelson testifies that customers will benefit from Rider QIP —through enhanced system reliability, including fewer and shorter outages than would otherwise be experienced.” (AmerenCILCO Ex. 2.0E at 30; AmerenCIPS Ex. 2.0E at 30; AmerenIP Ex. 2.0E at 30) Staff maintains that this higher quality of service is something ratepayers should normally expect from AIU--it should not be something for which they have to pay extra. Furthermore, Staff relates that AIU has a statutory obligation to provide safe and reliable service at minimum cost. Staff argues that AIU should not receive an additional financial reward, as would be provided by Rider QIP, to fulfill this obligation to maintain a safe and reliable system.

AIU examined two other riders when drafting its proposed Rider QIP. One is the Qualifying Infrastructure Plant Surcharge Rider of IAWC. The second is the Infrastructure Cost Recovery Rider proposed in the recent North Shore/Peoples rate case. AIU argues that following a similar approach to these riders supports the Commission‘s goal of promoting —uniformity of common riders.” The similarity of Rider QIP to the North Shore/Peoples proposed rider, however, causes Staff to urge caution since the Commission rejected the North Shore/Peoples proposed rider. (See Docket Nos. 07-0241/07-0242 (Cons.), Order at 162) Staff argues that AIU has failed to provide the full range of information discussed by the Commission and, therefore, AIU‘s proposed Rider QIP falls short of the standard set in Docket Nos. 07-0241/07-0242 (Cons.).

Staff recommends further that if the methodology for recovering investments in infrastructure is to be changed, that change should not be made in this rate case. Staff witness Stoller argues that the facts and policies involved should be thoroughly reviewed in a focused and separate proceeding. Mr. Stoller suggests that the Commission give serious consideration to initiating a proceeding to examine "evolving" utility service quality standards, and possibly to changing the provisions of the Commission‘s rules at 83 Ill. Adm. Code 410, "Standards of Service for Electric Utilities and Alternative Retail Electric Suppliers" ("Part 410"), and 83 Ill. Adm. Code 411, "Electric Reliability" (—Part 411”), consistent with modifications, if any, that need to be made to those rules regarding electric distribution system investment.

Mr. Stoller discusses AIU's perception of its inability to earn a fair return on investment in the maintenance and modernization of utility distribution systems. While utilities earn a return of and on their investment in their distribution systems, he notes that Mr. Nelson questions whether utilities earn a sufficient return on their investment to warrant investment that will improve their systems. Mr. Stoller states that the broader question may be whether the regulatory process effectively addresses distribution system reliability and whether changes are warranted to improve utility distribution systems. Answers to those broad policy questions would affect not only AIU, Mr. Stoller observes, but all utilities in Illinois.

Concerning the specifics of Rider QIP, Mr. Stoller does not offer a specific definition of what constitutes system modernization, but indicated that those are generally the type of projects to which he believed any expedited cost recovery mechanism such as Rider QIP should apply in its potentially broadest application. Mr. Stoller also recommends completely eliminating language that would make Rider QIP applicable to ―service reliability enhancements," saying that he believes that that definition is far too broad. Additionally, Mr. Stoller testifies that he does not believe that all utility work on a distribution system that could be claimed, or even agreed, to enhance service reliability should necessarily be entitled to expedited cost recovery. Such work could easily include such traditional projects as replacing old and rotted poles or simply replacing old distribution lines. Mr. Stoller acknowledges that while he is well aware that those projects can be valuable in maintaining and enhancing reliability, his position is that the Commission needs to be far more careful in defining what utility projects are entitled to expedited cost recovery treatment than to simply include in that category all projects that can be claimed or even demonstrated to enhance reliability.

If Rider QIP is implemented, Mr. Stoller agrees that a periodic filing and approval proceeding process would be a suitable approach. He is not prepared to agree that going through a process each year would be necessary or advisable, but states that having a known and predictable process in place would be beneficial for planning purposes for any party that might be interested in participating. He submits that perhaps the process should only occur at two-year intervals and perhaps the Commission approval process should be longer than the nine-month process that Mr. Nelson recommends. Mr. Stoller does not claim to have the answers to such questions, but suggests that they are questions that could be resolved in the collaborative process he recommends. Staff believes that Mr. Nelson's offer of payment to accompany such a filing is neither appropriate nor authorized by statute. Staff is concerned that the payment would create the appearance of impropriety.

If the Commission opts to follow his recommendation of a collaborative process, Mr. Stoller states that the participants should consider and make recommendations to the Commission regarding (1) the appropriate technological route or routes to follow for smart grid or other utility plant investment, (2) how to define which utility projects should be eligible for Rider QIP, or some other form of expedited cost recovery consideration, and (3) the process through which projects that might be considered for expedited cost recovery treatment should be proposed, evaluated, and approved and the time limitations for doing so. Mr. Stoller suggests that the collaborative process move on an expedited basis, but should not be time-limited in advance. He explains that neither the Commission nor any potential party knows at this time just how much information the parties might find it necessary to examine and how much time the parties may need to make recommendations. Only when the collaborative process is completed, and the Commission adopts the recommendations that it finds appropriate, does Mr. Stoller believe that Illinois utilities should file for Commission consideration a Rider QIP-type tariff, or if the Rider QIP tariff has already been approved in this proceeding, begin proposing projects for expedited cost recovery consideration and treatment.

3. AG's Position

The AG opposes implementation of Rider QIP. Some of the AG's general arguments regarding the appropriateness of riders in the above discussion of Rider VBA are also applicable to Rider QIP. Generally, with regard to Rider QIP, the AG contends that AIU has not provided any evidence of financial need for a rider for future distribution plant investments. In addition, the AG finds that the proposed Rider QIP is conceptually and mechanically flawed, would add considerable administrative burdens for Staff, interveners, and the Commission, and approval of the rider would conflict with the parameters of utility ratemaking outlined both in the Act and by Illinois courts.

a. Rider Treatment Eligibility

AG/CUB witness Brosch describes the general criteria employed by regulators to evaluate riders that are proposed as exceptions to traditional test year period regulation. The AG argues that Rider QIP fails every one of the general criteria that are routinely relied upon by regulators to evaluate rider proposals and highlighted by Illinois courts as appropriate for rider recovery. The AG asserts that the continuing investments that AIU makes in electric distribution are clearly not ―highly volatile or unpredictable," as evidenced by the fact that AIU management is able to control and budget such costs and make decisions regarding prioritization of capital spending. On the contrary, the AG observes, continuing plant investments are subject to rigorous investment screening, as discussed by AIU witness Getz, and only very gradually contribute to changes in rate base.

Likewise, the AG contends that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future *budgeted* electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of $157 million. Minimum spending of $121 million (23% less) occurred in 2005 and maximum planned spending of $181 million (15% more) is budgeted in 2008. AIU's historical *actual* capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006, the AG reports that actual annual Gross Construction Expenditures, as shown on page 5 of AIU's First Revised Schedule WPD-7, have ranged from $54 to $57 million per year for AmerenCILCO, $45 to $82 million for AmerenCIPS, and $134 to $177 million for AmerenIP.

Moreover, the AG asserts that new electric distribution plant investments can create productivity improvements and reductions in expenses that help AIU mitigate the costs of increasing capital investments. Significant amounts of electric distribution spending is targeted for reliability projects that are responsive to problem areas prone to excessive outages – and when older, unreliable plant is replaced, the AG states that savings are expected because of reduced outage restoration effort and expense in those areas. There are also opportunities, the AG adds, to deploy new technologies within the electric distribution network that are intended to capture expense savings. The AG points to the previously discussed four-year AMR project that began in 2006. AIU plans to expand AMR to an additional 1.1 million meters in Illinois by the end of 2009. The AG states that the primary reasons for investing in this large project are savings in operating cost and improvements in customer service enabled by AMR technology. The AG notes that AIU elected to deploy AMR under traditional regulation and without any extraordinary Rider QIP ratemaking treatment.

The amount of money to be generated by Rider QIP likewise is not significant enough in relation to the total revenue requirement to justify rider treatment, according to the AG. In its response to Data Request No. AG-1.30, AIU provides illustrative calculations of the quarterly Rider QIP calculations that would apply to its ―forecasted 2007 distribution plant additions" totaling $36.1 million. At this assumed spending level, the AG states that Rider QIP incremental quarterly and annual revenues would be $200,000 and would steadily ramp upward between rate cases as more plant is added each quarter. Extrapolating projected distribution plant additions at this pace, the AG continues, would suggest estimated annual revenue impacts of approximately $2.0 million in year one, $5.4 million in year two, and $9.2 million in year three (assuming no rate cases). While AIU has not justified its financial need for any of this incremental revenue, the AG goes on to say that by year three the incremental revenue of $9.2 million and corresponding incremental income after taxes of about $5.5 million is clearly not large in relation to total proposed electric utility operating income for the utilities of $189.3 million. Because the revenue requirement impact translates into only about 16% of the dollar amount of incremental capital spending, the AG asserts that AIU would need to vastly expand its planned electric distribution capital spending to experience the large or potentially volatile revenue requirement impacts that are normally required for special rider approval.

Furthermore, the AG insists that there is no evidence that traditional regulation has precluded AIU from taking advantage of cost effective opportunities to make or accelerate capital expenditures. The AG observes that to date, AIU has successfully modernized its network and, generally speaking, maintained reliability over the years, without benefit of an automatic rider recovery mechanism for distribution system modernization projects. AIU has been investing hundreds of millions of dollars in new plant every year in the normal course of business. Additionally, the AG notes that AIU fails to identify any particular investment project required to meet its service obligations to its customers that it could not make because of the absence of a mechanism like Rider QIP. Also of importance, the AG adds, is that all of those expenditures historically made by AIU were incurred without advanced Commission approval.

b. AIU's Current Budget Process

The AG reports that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. Similarly, Mr. Getz confirms that AIU has not specifically identified any projects that will be proposed in the rider. The AG professes amazement that Mr. Getz is unaware at this point as to how the Rider QIP process is to work. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects "that may not make the cut today." (Tr. at 606) This raises a question for the AG of whether the preferential ratemaking under Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses. (See generally Tr. at 600-606)

If Rider QIP is adopted, Mr. Brosch is concerned that the incentive for utility management to act prudently with expenditures between rate cases will be lost, or at least diminished. According to the AG, Mr. Getz confirms the efficiency of AIU's existing budget process under traditional regulation. Mr. Getz testifies that the existing method begins in April and typically ends in December. According to Mr. Getz, and AG Cross Exhibit 6, capital budgets are created for each of the three utilities based on approximately 20 internally defined budget groups, such as line transformers, meters, and distribution substations. Blanket or standing work orders are budgeted in April and reviewed by a Central Review Committee ("CRC") of managers to see if they seem reasonable in terms of the dollars that are identified and the rationale provided. The business performance supervisor reviews these in May. The process is designed, according to Mr. Getz, to ensure that allocated dollars are efficiently earmarked to ensure the availability of dollars for specific projects. Mr. Getz states that some projects are sent back to individual budget groups as rejected for further refinement. He adds that revisions are sometimes made to estimates. (See generally Tr. at 607-612)

The AG continues to describe AIU's budgeting process by relating that Mr. Getz testifies that engineers submit specific projects for consideration into the Integrated Spending Prioritization ("ISP") Tool during May of each year. These projects are typically valued at $100,000 or more. The ISP Tool is an "optimization program" with weightings based on safety, System Average Interruption Frequency Index reliability, and other factors that are applied to each specific project to rank the projects. According to Mr. Getz, the CRC meets in June to review specific project prioritization through the ISP Tool as well as budgeting personnel prioritization based on preliminary capital targets from the Treasurer's organization. Hard capital targets are established in August and any adjustments that need to be made are done so by the CRC. At this point, Mr. Getz explains, AIU is trying to "fine tune" the capital budget, with another review of the budget numbers developed in June. The recommended budget is then forwarded to the AIU President and Vice Presidents for review. (See generally AG Cross Exhibit 6 and Tr. at 613-616)

Mr. Getz confirms that this capital budget process is designed to include checks and balances that contribute to the provision of reliable service while maintaining AIU's shareholders' and ratepayers' financial interests. In addition, he verifies that this budget process helps ensure that AIU invests in capital projects that are needed for both reliability and to meet customer demand for services. Mr. Getz asserts that the existing capital budget process —does a good job of prioritizing" capital spending, and that these checks and balances have helped ensure that AIU's electric rates are least cost from the customers' perspective. (Tr. at 618)

The AG finds it ironic that, if approved, Rider QIP would reduce the normal regulatory lag incentive that a utility faces between rate cases, and provided evidence of such incentive in the above-described AIU capital budget process. Such a reduction serves to encourage careful management and optimization of capital expenditures. The AG is concerned that Rider QIP would provide expedited piecemeal rate increases for incremental qualifying capital investment between rate case test years, and diminish management's obligation to carefully manage and optimize capital expenditure levels. When asked during cross-examination whether Rider QIP projects would run through the existing capital budget process, the AG reports that Mr. Getz testified that he was —not sure what the plan is going forward, or, you know, what the process is envisioned to be." (Tr. at 598)

The AG further argues that there is no evidence that AIU faces a financing problem that makes Rider QIP necessary. The AG notes AIU witness Nelson's testimony that, "(w)ithout a ready source of rate recovery for capital investments, there is no way to pay interest to debt providers or to pay dividends and provide a return to equity investors." (AmerenCILCO Ex. 2.0E at 28) The AG considers it significant that Mr. Nelson does not state that AIU is unable or unwilling to invest in new plant. The AG asserts, that AIU enjoys considerable cash flow from its regulated operations in Illinois and expects to continue to be able to finance most of its planned construction expenditures from internally generated cash flow from operations. In its response to Data Request No. AG (MLB) 3.09, AIU provided its most recent confidential financial projections of income, balances sheets, and cash flows for the years 2008-2010 assuming no rate relief is granted in the pending rate cases. Mr. Brosch finds it instructive that AIU expects to generate virtually all of the capital needed to finance planned construction activities in Illinois from the cash flows produced by consolidated utility operations (rather than capital markets), as shown in the proprietary table at page 61 of his direct testimony. From this information, the AG contends that it is clear that Rider QIP is not needed by AIU to provide access to capital markets on reasonable terms, because traditional ratemaking and the strong cash flows arising from operating income and the collection of depreciation for existing plant service generates most or all of the cash required by AIU for new investment in Illinois.

c. Ambiguity Concerns

Under Rider QIP, capitalized expenditures related to existing distribution plant, but not those additions associated with new customers, would qualify for the rider. In addition, the rider lists nine accounts for which cost recovery under Rider QIP is possible. According to Mr. Nelson, Rider QIP projects include only those "associated with system modernization or service reliability enhancement." The AG, however, is still concerned that the terms of Rider QIP may permit AIU to recover nearly any plant investment under Rider QIP. For example, the AG notes that under cross-examination, AIU witness Cooper acknowledged that the majority of capital investment projects for electric delivery service would be listed under these nine accounts. (Tr. at 514)

Additionally, Mr. Brosch notes that it is often difficult to distinguish whether specific electric distribution projects are partially driven by growth in customer demand. The AG argues that new investments made to extend distribution lines and to connect new customers with meters and services should clearly be excluded from Rider QIP because AIU desires retention of new business margin revenue for its shareholders between test years. Mr. Brosch adds that construction costs incurred to replace existing facilities with larger and newer facilities may not be solely related to either growth or reliability, but instead be driven by a combined need to replace obsolete or unreliable equipment as well as a need to expand capacity of existing circuits. When asked in Data Request No. AG 1.39(b) to clarify how Rider QIP would apply to —capital expenditures that are made to increase the capacity of existing primary distribution feeders to accommodate growth in demand caused by new customers in the area served," the AG relates that AIU responded, —If the reason for the distribution feeder project was triggered *solely* by the demand growth of new customers added subsequent to the test year period for the most recent rate case, then none of the project capital expenditures would qualify for QIP treatment" (emphasis added). The AG interprets this to mean that any project driven jointly to meet demand growth and address reliability concerns would fully qualify for Rider QIP inclusion, under this liberal interpretation of the project inclusion criteria AIU is proposing for the rider.

With regard to the phrase "system modernization or service reliability enhancement," Mr. Brosch notes that —system modernization" is a vague term that is not defined anywhere in AIU's rebuttal testimony and could be construed to include virtually any project that employs currently available materials or technologies to replace older, existing plant assets. The same is true, he continues, for the new —service reliability enhancement" classification proposal, because the replacement of nearly any older or deteriorated plant asset with newer materials or equipment could reduce the possibility of failure and customer outage and thereby enhance reliability.

With respect to the proposed filing of cost/benefit analyses, the AG is troubled by the fact that no details are provided to explain what methodologies or cost/benefit metrics are to be employed or what level of detail or accuracy will be contained in such —analyses." Given the vague definition of types of modernization or reliability projects that may be proposed as well as the complete lack of details regarding how the promised cost/benefit analyses will be performed or measured, it is impossible for the AG to tell how much or little detailed information would be contained in the proposed annual filings and related analyses. The AG believes that it is conceivable that each annual filing by AIU may contain a large number of individual capital projects, each with some level of supporting economic analysis that requires detailed discovery and study by Staff and any concerned interveners before any informed Commission deliberation or approval of charges to customers could occur. In apparent recognition of the regulatory burden these filings would represent, the AG notes that AIU offered to contribute $100,000 to the Commission to fund Staff (but not interveners‘) review of these filings. The AG adds that it is unclear whether AIU intends to try to pass this $100,000 through to customers.

When asked by the AG in discovery to provide a specimen copy of a cost/benefit analysis, AIU responded by stating, “The form of the cost/benefit analysis has not yet been drafted; however, AIU intend that it be similar to that which the Commission described in its Order in the recent Peoples/North Shore case.” The AG finds the reference to the Commission‘s Order in Docket Nos. 07-0241/07-0242 (Cons.) unhelpful since the Commission did not prescribe any form of cost/benefit analysis. Rather, the Commission listed some additional information that might have made it easier to approve the proposed infrastructure rider. The AG asserts that AIU should not be allowed to implement Rider QIP by simply indicating the intent to comply with cost/benefit analyses that are largely undefined.

In addition, the AG states that Rider QIP is flawed in its failure to account for two elements of the revenue requirement calculation that change in direct relation to changes in gross plant investment – the accumulated deferred income tax reserve and the accumulated depreciation and amortization reserve. Since these balances are treated as subtractions in determining rate base, the AG avers that it is completely unreasonable for AIU to include gross plant additions within Rider QIP and not also include the growing deferred income tax and accumulated depreciation balances that also tend to increase from year to year. Mr. Brosch explains that the rider is driven by quantification of the term “Net QIP” in the tariff, which includes the “Original cost of QIP less accumulated depreciation.” By defining qualifying investment this way, the tariff completely fails to account for the additional deferred income taxes arising from the incremental plant investment. Mr. Brosch also contends that there is also a problem with the narrowly defined “less accum depr” term that is used to quantify “Net QIP.” The accumulated depreciation that is recognized under Rider QIP is limited to depreciation accruals only upon the new QIP Plant investment dollars. According to Mr. Brosch, in reality, AIU continues to collect depreciation and build its Accumulated Reserve for Depreciation based upon application of depreciation accrual rates to all plant investment, not just incremental new investment. In fact, he explains, depreciation on embedded prior year capital investment produces considerable cash flow for QIP that is available for reinvestment in incremental new plant, as shown in Table 9 (page 61) of AG/CUB Ex. 2.0, and that can not be ignored if a balanced tracking of changes in actual net plant investment is to be achieved through any rider tariff.

The AG identifies other mechanical difficulties in auditing Ride QIP. The AG states that neither the input values nor the computations involved in administering Rider QIP plant investment can be readily audited and verified through expedited regulatory reviews. Rider QIP relies upon several input values that should become “fixed” in this rate case, including the gross revenue conversion factor “GRCF” and the weighted cost of capital inputs "WCCE," "WCPE," "WCLTD," and "WCSTD." But, according to the AG, the quarterly capital expenditure amounts in each account that qualify for inclusion in all the calculations would need to be verified for each quarterly filing and then again in annual reconciliation filings, with interest accrued on over and under-recoveries. The complexity of the calculations involved in administering Rider QIP is evident to the AG from the four pages of single-spaced text required in AIU witness Cooper‘s testimony just to define the terms involved, before any data is actually analyzed or rates calculated.

AIU apparently contemplates rapid implementation of Rider QIP quarterly rate increases, with an informational filing on the 20th day of the month preceding the effective date of the QIP surcharge percentage, which the AG fears would allow no substantive analysis or audit of the plant costs that would cause such rate increases. The AG believes that Rider QIP raises a fundamental question regarding whether it is necessary for any Staff audit or other regulatory examination to occur before new plant investments can be included within rate base for cost recovery from customers. The primary input values under Rider QIP would be the “NetQIP” recorded original cost plant additions recorded each quarter, reduced by project costs that relate to “new business.” In the event the Commission or Staff determine that any prudence review or financial audit of recorded plant investments is required prior to increasing rates to recover the incremental new NetQIP plant investment, the AG states that considerable administrative costs and procedural delays may be unavoidable with implementation of Rider QIP.

d. Legal Considerations

Among the statutory provisions that the AG has considered is Section 9-211 of the Act, which provides that a utility's rate base shall reflect only the value of such investment which is both prudently incurred and used and useful in providing service to customers. The AG contends that Rider QIP violates this precept since it permits surcharges on customer bills to cover the carrying costs of new investment before there has been any Commission review of the prudency or used and usefulness of the Rider QIP investments. While Rider QIP would include an after-the-fact prudency review as part of the annual reconciliation of the preceding calendar year rider surcharges, the AG points out that customer rates would have already increased, reflecting investment prior to any prudency assessment. The AG also objects to Rider QIP on the legal grounds that it violates the rule on single-issue ratemaking, least-cost requirements, and many of the other legal principles that it discusses in the context of Rider VBA.

4. CUB's Position

CUB objects to the implementation of Rider QIP, citing in defense of its position the rule on single-issue ratemaking, the broad scope of eligible projects under Rider QIP, the lack of any specific project plans, the delay in any customer receipt of savings, and the improper transfer of risk from shareholders to customers. CUB also states that to the extent AIU's request for Rider QIP is based on the eventual implementation of a smart grid, the rider should be rejected given AIU's lack of specificity with regard to smart grid implementation. CUB witness Cohen, though not opposed to implementation of a true smart grid where the benefits outweigh the costs, takes issue with the propriety of rider treatment for smart grid investments. Instead, Mr. Cohen recommends that the Commission order immediate commencement of a collaborative stakeholder process to examine the changing nature of the utilities‘ service obligations and address the costs and benefits of particular smart grid strategies. He testifies that the stakeholder process should be led by an independent expert facilitator with experience in similar processes elsewhere, who could assimilate the latest technical information and regulatory policy from around the country in a highly specialized and rapidly evolving field. Mr. Cohen believes that a high level of experience with similar processes will enable the facilitator to set the agenda, manage the flow of information, and focus the collaborative on timely achievement of its goals.

Mr. Cohen further recommends that the Commission order a statewide process to consider smart grid and related issues, in order to ensure that uniform principles, policies, and standards are applied where appropriate.

Mr. Cohen and CUB witness Kiesling both testify about the vast potential benefits of a true smart grid, but also caution that such benefits will only be realized if the Commission approaches smart grid planning strategically, and with ratepayers‘ best interests in mind. Mr. Cohen states that a true smart grid has the potential to facilitate optimal procurement planning as well as other system benefits. Smart grid technologies integrate electric generation, delivery, and consumption systems with communication systems to improve system function and reliability and also potentially to provide a variety of electricity products and services to the diverse range of customers in the electricity network. Further, smart grid holds the potential to reduce operating and maintenance costs while improving reliability, as well as reduce the cost of long-run generation, transmission, and distribution investments by reducing peak load.

Ms. Kiesling lays out the necessary foundations for any smart grid planning process and advises that this Commission should approach smart grid investment from a proactive and strategic policy framework stand point, rather than the reactive approach. She explains why a utility-specific system engineering process is essential at the outset, the danger of premature commitment to a particular technology, and the need to ―future-proof" smart grid decision-making. Ms. Kiesling identifies the following characteristics as defining a true smart grid:

- Self-healing: a smart grid can measure voltage and frequency and detect and prevent faults and outages automatically;
- Active agent participation: customers actively participate in the network, as with demand response programs;
- Security: built-in resiliency to external attacks on the network;
- Power quality: customers can demand interruptible power supplies in exchange for lower prices;
- Interconnection: distributed generation and storage sources can interconnect within the network;
- Markets: a smart grid is a transactive, market-based network; and
- Efficiency: a smart grid optimizes resource use and minimizes waste and idle capacity.

To assist in the effective design of a smart grid, she reports that there has been industry movement toward common smart grid architecture. Ms. Kiesling cites the GridWise Architecture Council (“GWAC”), a group of experts formed by the U.S. Department of Energy, as the gold standard in interoperability principles and architectural frameworks to facilitate the smart grid.

Ms. Kiesling testifies that GWAC is dedicated to the development of interoperability principles for the modernization of the electric power network, and to facilitating the implementation of these principles. One of the GWAC‘s roles, she continues, is to help stakeholders understand these principles, and to provide resources to help facilitate an interoperable, modern, smart electric power network. The GWAC‘s Decision-Maker‘s Interoperability Checklist is a tool to help decision-makers evaluate options such as capital asset investments or new information technology opportunities to determine whether they contribute to interoperability. Ms. Kiesling states that decision-makers can use the checklist to review policies or infrastructure investment proposals. She recommends that these standards be applied in a multi-party process that creates a long-term smart grid strategy for AIU.

CUB asserts that the collaborative process recommended by Mr. Cohen and Ms. Kiesling would address foundational policies, as well as incorporate utility-specific issues. CUB states that policies for consideration could include, but not be limited to:

- Defining the intended functionalities and properties of a true smart grid;
- Delineating principles Illinois should use to guide smart grid planning and deployment, for example:
  - Interoperability;
  - Open Architecture; and
  - Non-discriminatory Access;
- Developing uniform Standards;
- Establishing methods of estimating, calculating, and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs);
- Identifying the implications of smart grid technology for existing policies regarding rate design, consumer protection, and customer choice;

- Evaluating the effect of statutory renewable resource, demand response, and energy efficiency goals on smart grid planning and implementation;
- Considering the import of consumer education and dissemination of information about smart grid applications;
- Access by electricity market participants to smart grid functionalities;
- Data collection, storage, management, security, and availability to third parties;
- Standards for interconnection of third party equipment; and
- Mechanisms to flow through to customers any utility smart grid revenues.

CUB adds that a critical input into the collaborative process would be information derived through internal utility design and engineering exercises using established national models, and tools to identify functionality requirements and technical standards. Ms. Kiesling further testifies that the development of a long-term smart grid strategy should include an implementation management process, facilitated by an independent third-party technical expert, who welcomes the participation of parties beyond the utility, develops specific functionality requirements, and incorporates industry-supported interoperability standards and other architecture standards.

In order to ensure sufficient interoperability, which in turn enables information sharing, enhances the reliability and effectiveness of operational and commercial functions, and a host of additional system benefits, CUB further contends that the following Interoperability Principles must be present in any smart grid plan (as reflected in the GWAC Constitution Statements of Principle):

- Respect organizational boundaries and security across the electric system supply chain. Electric system business processes must become better automated across the value chain, while respecting privacy and each business' internal processes.
- Embrace the evolutionary dynamics of business processes, technologies, and interfaces. Over time, business processes evolve and the information system interfaces that support them are smoothly modified.
- Enable the discovery and creation of new value chains and participants. New players become active participants by accessing and delivering services through information system interfaces with other organizations.
- Enhance the resilience of the system to natural or deliberate attacks. Automation with independent, distributed decision-making schemes promotes reconfiguration of the electric grid to protect and mitigate impacts.

CUB maintains that Rider QIP is incomplete and does not require the interoperability needed to ensure that these benefits are achieved. AIU's current proposal, CUB observes, includes only four criteria for smart grid investments, instead of the more comprehensive criteria listed above and discussed in more detail by Ms. Kiesling. CUB asserts that these criteria are necessary to ensure that smart grid investments are fully beneficial to AIU, customers, and the electric grid.

5. IIEC's Position

IIEC argues that Rider QIP suffers from the various problems that beset riders generally and urges the Commission to reject it and include such capital projects in annual capital budgeting processes as they are currently. IIEC states that AIU may include within the scope of Rider QIP projects such as ordinary replacements routinely performed today. Thus, IIEC believes that it is reasonable to expect that without Rider QIP AIU would continue to invest in the types of projects envisioned under Rider QIP, on the same bases it now uses for initiating construction projects, and would seek appropriate rate base treatment in its next general rate proceedings just as it does today.

Through Rider QIP, IIEC contends that AIU is attempting to shift to its customers operating risk that is traditionally borne by the utility and addressed in a traditional rate case proceeding. AIU, however, does not view rider recovery as shifting operational risk--AIU believes it merely neutralizes the risk. IIEC agrees that risks may be neutralized from a utility's perspective, but the effect is quite different from a customer's perspective. IIEC is concerned that Rider QIP would allow AIU to avoid the quantitative assessments central to rate cases that determine whether it is reasonable and prudent to replace particular facilities. While qualifying investments might eventually get the traditional level of scrutiny before permanent inclusion in base rates, IIEC asserts that the rider procedures do not provide the same apportionment of risk achieved under traditional regulation, and do not allow close scrutiny of proposed costs until after customers are charged. Despite AIU's risk neutralization theory, IIEC maintains that the near immediate rate recovery of and on new investment undeniably constitutes a major shift in operating risk to the customer.

IIEC is also troubled by the fact that Rider QIP adjusts rates on the basis of only selected cost elements, without taking into consideration other costs or factors that would affect the utility's overall profitability. AIU fails to acknowledge that savings, along with other factors that serve to reduce the revenue requirement, e.g., changes in the depreciation reserve, may negate the need for a separate rider altogether. Another concern of IIEC's is that Rider QIP also provides additional revenue to AIU without the traditional Commission review to determine the prudence of the cost and revenue elements. IIEC contends that the ratemaking approach represented by Rider QIP bears a striking resemblance to single-issue ratemaking and, thus, should be avoided.

Rider QIP's potential to distort or otherwise compromise the incentives for prudent and efficient utility operation built into the regulatory oversight and ratemaking process worries IIEC as well. IIEC states Rider QIP may create an incentive for AIU to classify expenses in a way that maximizes rider collections, rather than foregoing recovery until its next rate case. Under Rider QIP, such choices are not transparent, and IIEC believes that they would increase the difficulty of the Commission's evaluation of AIU's costs in subsequent rate proceedings. Regulatory lag will also no longer provide an incentive to control costs in order to be more profitable to shareholders and to diminish the need for future rate cases. The relatively immediate dollar-for-dollar recovery of eligible costs, IIEC avers, eliminates the beneficial impact of regulatory lag.

IIEC indicates that Rider QIP will also potentially create new cross-subsidies. IIEC witness Stephens testifies that if the structure of a rider is such that it collects revenues from customers on bases different from those used in recovering similar costs through base rates, or if the rider is otherwise not reflective of cost-causation, it creates a subsidy and should not be approved. In addition to the forecasted capital and O&M expenditures listed by Mr. Nelson, AIU is studying smart metering and smart grid technologies that AIU claims may provide future benefit to customers. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice. In a traditional comprehensive rate case, with appropriate cost studies, IIEC states that facilities deployed to enhance the reliability of the delivery system would likely be allocated among potential beneficiaries on the same basis as the assets made more reliable. Rider QIP does not incorporate any process to allocate costs to those who receive the direct benefit of the investment eligible for cost recovery under the rider. Therefore, of necessity there will be cost subsidies in favor of those customers that do directly benefit, according to IIEC.

An additional problem with Rider QIP identified by IIEC is that the rider seeks to recover costs that need not be incurred to meet AIU's statutory service obligations. Through Rider QIP, AIU seeks to study and invest in smart grid technologies. A smart or modernized grid is a delivery system that uses advanced sensing, communication, and control technologies to generate and distribute electricity more effectively, economically, and securely. These capabilities, IIEC argues, in addition to not being proven, are not needed to meet AIU's service obligations. To the extent that AIU's proposed smart grid projects under Rider QIP are necessary or beneficial to consumers and determined to be good, prudent projects to undertake, IIEC contends that AIU should address them as part of the normal capital budgeting process and seek recovery in its next rate case. IIEC notes that AIU began a 4-year deployment of AMR technology in May 2006 and has apparently been able to deploy this technology as part of its normal budgeting process.

IIEC opines that Rider QIP projects also could allow AIU to provide services on a competitive basis. While it is not clear exactly what functionalities ultimately will be available through a smart grid or other advanced technologies, AIU mentions in its testimony that it is conceivable that those functionalities will allow it to provide services that extend well beyond those associated with electric delivery service. IIEC indicates that there may be new business opportunities for AIU, or an unregulated affiliate, to provide value added services related to data management, energy facilities management, or even voice or data communications all underwritten through regulated rates.

From an administrative standpoint, IIEC contends that Rider QIP will require increased regulatory complexity that will be burdensome for many stakeholders. AIU has committed to paying a combined annual fee of $100,000 for the annual filings to mitigate the burden on Commission resources. Outside of the $100,000 pledge, AIU is short on details as to the proposed process and procedure for the Commission pre-approval. As AIU's annual $100,000 pledge to the Commission demonstrates, IIEC states that participation in repeated regulatory proceedings before the Commission can be an expensive proposition for intervener parties. In fact, IIEC relates that AIU does not even know if $100,000 is sufficient to mitigate the drain on the Commission resources. Furthermore, AIU has not given consideration to paying the participation fees of other parties. No matter the level of participation, IIEC fears that the evaluation and study likely will be less than that which would typically occur in a general rate case.

6. AARP's Position

AARP objects to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. In terms of legal arguments, AARP asserts that Section 9-211 of the Act requires that the determination of any rate or charge shall include only investment that is prudently incurred and is used and useful in providing service to customers. AARP states further that Section 9-215 charges the Commission with the task of determining whether a utility's capacity is in —excess of that reasonably necessary to provide adequate and reliable electric service." Section 8-401, AARP adds, requires Illinois public utilities to provide service and facilities in a manner that constitutes the —least cost of meeting the utility's service obligations." AARP claims that this legal framework for ratemaking would be violated by AIU's proposal to fund projects that exceed its basic obligations through a mandatory surcharge. Rider QIP, AARP argues, is fundamentally at odds with Illinois law, especially if it were approved as an —empty rider" with particular projects to be determined through subsequent Commission proceedings. AARP contends that such a decision would establish a —blank check" to be filled in later—outside the full review and protections provided to consumers by a general rate case. The law requires, AARP insists, that basic electric delivery rates be limited to funding only those projects that do not exceed the least cost method of providing what is necessary for adequate and reliable electric service. AARP states further that Rider QIP violates the general rule against single-issue ratemaking.

Among the policy reasons that Rider QIP should be rejected, according to AARP, is the fact that it would inappropriately shift the responsibility and risk of capital investment between rate cases away from shareholders and onto ratepayers. If AIU believes that its expenses or costs, including the cost of financing distribution system capital additions, are increasing more rapidly than its revenues such that a revenue deficiency is being created, AARP reminds AIU that it has the option to file for a rate increase. AARP notes that AIU has not identified any prohibitions on its ability to file base rate cases to address distribution system plant additions. Currently, the risks and benefits lie with shareholders during the period between rate cases if revenues grow more slowly or more rapidly than AIU's costs. AARP argues that Rider QIP would shift the risk of financing distribution system capital investment onto ratepayers by making ratepayers responsible for capital expenditures between rate cases. AARP observes, however, that AIU would still retain the benefit of revenue growth and expense reductions between rate cases for its shareholders. AARP contends that such a non-symmetrical ratemaking approach is extremely unfair to consumers.

A second policy reason discussed by AARP as to why Rider QIP is inappropriate is that it would remove or reduce the current incentives to prudently control the cost of plant additions. One of the useful functions of regulatory lag is to place financial responsibility upon the utility for fluctuations in costs between rate cases. AARP states that the regulatory lag feature of Rate Base/Rate of Return regulation is essential to effective and efficient operation of such a regulatory régime. In evaluating plant additions, AARP states that AIU should conduct a cost-benefit analysis to determine if there is a business case for making the expenditure and for prioritizing between competing uses of capital resources. If the case is compelling and the project is cost-justified, AARP contends that no additional rider or adjustment clause is needed. If the project is not cost-justified or the benefits are too speculative to warrant the commitment of funds, AARP suggests that it may be prudent to delay or avoid the related capital expenditures. These incentives that are currently in place would essentially be eliminated if Rider QIP were to be approved, according to AARP.

AARP's third policy argument against approval of Rider QIP is that the costs at issue are not appropriate for rider recovery. Despite AIU's claims, AARP contends that the distribution system costs that could be included in Rider QIP would not be similar to power supply costs. AARP notes AIU's acknowledgment that a rider mechanism is a more appropriate cost-recovery mechanism for costs and other rate inputs that are highly volatile, uncontrollable, and/or unpredictable. AARP contends, however, that distribution system capital investments and plant additions generally are not highly volatile, uncontrollable, and/or unpredictable. Many electric utilities have adjustment clauses to address the rate recovery of their large and volatile fuel and purchased power costs, and the primary factor typically cited in justifying the implementation of fuel and purchased power cost recovery mechanisms is that these costs are highly volatile, uncontrollable, and/or unpredictable. AARP asserts that distribution system capital additions are very different and offers the table on page 10 of AARP Ex. 1.0 to demonstrate the differences.

A fourth policy argument against Rider QIP is that it is simply not needed. AARP observes that the lack of such a rider has apparently not deterred AIU from making investments in the past which were necessary to meet its service obligations to its customers. Consequently, AARP contends that it is not appropriate to now set aside this one single issue for future recovery.

AARP's fifth argument against Rider QIP concerns Mr. Nelson's testimony that Rider QIP would facilitate investments in smart metering and smart grid technology. AARP is troubled, however, by the fact that AIU is still evaluating the benefits, costs, and timing associated with implementing smart metering and smart grid technologies and has no firm plans in place at this time. AARP maintains that AIU should not be given the go-ahead to shift the risk of such projects that it may not otherwise construct, and which would not meet AIU's normal financial and economic analysis and capital expenditure prioritization screening, particularly when it has no definitive plan. AARP reminds the Commission that the concepts of smart grid and smart metering are not a replacement for aging infrastructure but rather an entirely new system that would be placed on top of the basic electric delivery system—the cost of which should definitely not be passed through a rider.

AIU would be better served, according to AARP, to look at other electric utilities that are implementing smart grid projects on an experimental basis without seeking advanced regulatory approval to charge the costs incurred to ratepayers. As an example, AARP points to Xcel Energy ("Xcel"), which has recently announced its plans to implement an advanced, smart grid system in Boulder, Colorado. (See AARP Exs. 2.1 and 2.2) Having established a collaborative effort with other firms and leveraging other sources including governmental grants, AARP reports that Xcel anticipates funding only a portion of the smart grid project itself. AARP adds that Xcel is not seeking permission from regulators to recover its costs in advance, but will wait until it has assessed and proven the benefits. AARP states that the approach advanced by Xcel, where the utility is assuming the initial risks of installing smart grid technology and evaluating whether it is producing benefits (consistent with the very underpinnings of rate of return regulation), stands in stark contrast with AIU's approach.

AARP's sixth policy argument against Rider QIP relates to the future project reviews before the Commission. Specifically, AARP believes that it is unlikely that it would have funding for legal and consultant participation in those subsequent proceedings or the proposed annual Rider QIP reviews. Although AIU offers to contribute money to offset the impact on Staff's resources, AARP notes that AIU made no such offer to interveners. Under the general Rider QIP process set forth in the record, AARP fears that intervener participation is likely to suffer. Consequently, AARP would prefer to see AIU's capital projects continue to be addressed in the context of general rate cases, and not be forced to consider representation in additional separate proceedings in order to provide input on rate increases outside of the protections of such general rate cases.

7. LGI's Position

LGI urges the Commission to reject Rider QIP. To begin with, LGI indicates that Rider QIP is no better than the comparable infrastructure rider recently rejected by the Commission in Docket Nos. 07-0241/07-0242 (Cons.). LGI also contends that Rider QIP violates the rule against single-issue ratemaking, since it does not consider any other impacts on costs. The rider, LGI adds, inappropriately shifts the operating risk from AIU to customers since it seeks preapproval of a project and guarantees that AIU will recover not only its costs but also a return on its investment. By granting approval between rate cases, LGI states that Rider QIP eliminates the regulatory lag for recovery of expenses and through a yearly process it will unduly burden customers who must spend additional funds to intervene and participate in the annual approval process. LGI concurs with AG/CUB witness Brosch and Staff witness Stoller that the definitions contained in Rider QIP are far too broad and cover routine items that are typically and more appropriately considered in a traditional rate case. If implementation of a smart grid is a goal, LGI also agrees that interested parties should first collaborate on what needs/ought to be done before essentially using Rider QIP to pay for whatever AIU decides to do.

8. Kroger's Position

Kroger argues that Rider QIP should be rejected as a form of single-issue ratemaking. When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers, Kroger notes that the standard practice is to review and consider all relevant factors, rather than just a single factor. To consider some costs in isolation might cause a commission to allow a utility to increase rates to recover higher costs in one area without recognizing counterbalancing savings in another area. Furthermore, Kroger maintains that the facts surrounding Rider QIP do not trigger any of the exceptions to the general prohibition against single-issue ratemaking.

As a public utility, Kroger asserts that it is AIU's responsibility to provide safe and reliable service to its customers. In meeting this responsibility, Kroger states that AIU must set budget priorities and invest sufficient capital to maintain and improve its system. The responsibility, Kroger continues, to ensure that proper investment priorities are developed and implemented rests with AIU's management. If system improvement projects are prudent investments, Kroger contends that management should fund them and seek cost recovery through conventional ratemaking treatment. Kroger does not believe that it is in the public interest to resort to single-issue ratemaking to ensure funding of necessary distribution infrastructure.

9. Commercial Group's Position

The Commercial Group indicates that its members have operations across the United States and have noticed an increase in applications by utilities for rider recovery of various costs. The Commercial Group believes that such rider recovery mechanisms shift risk of recovery of costs between rate cases from the utility to ratepayers. Therefore, it contends that riders should only be approved in extreme situations pursuant to established legal standards. According to the Commercial Group, Rider QIP does not meet these standards.

Under Rider QIP, the Commercial Group states that AIU could recover costs incurred between rate cases without a prudency or reasonable cost finding and without a corresponding cost reduction analysis. The Commercial Group considers this single-issue ratemaking that would increase rates overall. Furthermore, it adds, none of the costs in question are extraordinary or volatile in nature so as to justify rider recovery.

Instead, the Commercial Group contends that some of these investments appear discretionary in nature and might not be made by AIU if Rider QIP is not approved and could produce revenue streams from new non-essential services. Therefore, if recovery of discretionary plant costs is to be allowed that may produce non-utility revenue, the Commercial Group recommends that more administrative oversight be required to ensure that ratepayers do not overpay for utility service. The Commercial Group, however, contends that it would be administratively difficult for it to participate in the "extra" proceedings contemplated under Rider QIP. It notes that it is expensive and cumbersome enough for interveners to hire consultants and attorneys for rate cases. Expecting them to do so for additional Rider QIP proceedings is not realistic. Thus, the Commercial Group fears that intervener input would effectively be eliminated from a significant portion of costs that by their nature require more, not less, oversight.

10. Commission Conclusion

Clearly Rider QIP has generated a great deal of controversy. While the Commission certainly does not object to the general idea of improving the electric distribution system (including implementation of smart grid technology), care must be given to ensure that it is done in a practical and cost effective manner. Cost recovery for such efforts must also be thought through. AIU proposes to recover capitalized expenditures related to system modernization and service reliability enhancements through Rider QIP. Every other party to this proceeding generally considers a rider an inappropriate way to recover such costs, for both legal and practical reasons.

The Commission has recently given the use of riders as a cost recovery mechanism a great deal of thought (see Docket Nos. 07-0241/07-0242 (Cons.)). In the proper case, riders may be used to recover certain utility costs. Typically such costs are unexpected, volatile, or fluctuating expenses, as discussed in BPI II. With regard to Rider QIP, AIU hopes to use it to recover several hundred million dollars in capital expenditures related to infrastructure improvement over a period of years. Several of the parties argue that the types of projects/expenditures that AIU seeks to pass through under Rider QIP are not unexpected, volatile, or fluctuating. IIEC contends that the long-term, planned system improvements that AIU describes (See AmerenIP Ex. 2.0E at 27-28) are the most expected, least unpredictable, and most controllable of utility costs. IIEC therefore maintains that they should receive comprehensive review and approval, not truncated examination and pre-approval under a rider.

To bolster the argument that the expenses at issue are not appropriate for rider treatment, the AG asserts that AIU's historical and projected investment levels in electric distribution plant do not indicate cost volatility or any apparent inability to manage and control spending. The AG relates that past and future budgeted electric distribution plant spending has been and is expected to remain relatively stable, with an average expenditure level for the period of 2004 through 2011 of $157 million. Minimum spending of $121 million (23% less) occurred in 2005 and maximum planned spending of $181 million (15% more) is budgeted in 2008. AIU's historical actual capital expenditure levels have been similarly non-volatile. For the years 2004 through 2006, the AG reports that actual annual Gross Construction Expenditures, as shown on AIU's First Revised Schedule WPD-7, page 5, have ranged from $54 to $57 million per year for AmerenCILCO, $45 to $82 million for AmerenCIPS, and $134 to $177 million for AmerenIP.

Upon reviewing the record, the Commission is not convinced that the costs in question are appropriate for rider treatment. While AIU argues that the amounts are significant and will allow it to improve the reliability of its distribution systems, the Commission does not believe that they rise to a level necessitating rider treatment nor are they for projects whose nature warrants rider treatment. The projects/activities identified by AIU witness Nelson include, among others, pole replacement, line rebuilding, transformer purchases, inspections, and tree trimming. The costs for these types of projects and activities are typically addressed in a rate case since they are consistent with the everyday business of operating and maintaining an electricity distribution company. Some such projects may also reduce operating expenses; since there is no mechanism to pass savings on to customers, the specter of single-issue ratemaking arises as well.

Additionally, the Commission questions whether a financial need for such rider treatment exists in order to fund the projects described. AIU has offered no compelling evidence of financial need. The AG points out that AMS' Managing Supervisor of Business Performance, Mr. Getz, oversees the capital budget process and testifies that he was unaware of any specific projects that AIU was unable to finance through internally generated funds and the capital markets that would be appropriate for Rider QIP inclusion. The AG is also concerned by Mr. Getz's testimony that Rider QIP would simply provide additional funds for the financing of capital projects "that may not make the cut today." (Tr. at 606) The Commission concurs with the AG that such testimony raises a question of whether Rider QIP may induce AIU to invest in certain capital projects that are otherwise only marginally justified under AIU's economic analyses.

Even for those projects which may go beyond the customary operation and maintenance expenses, AIU has failed to persuade the Commission that Rider QIP is necessary. In fact, the Commission notes that AIU elected to deploy AMR under traditional regulation and without any rider recovery mechanism. The Commission sees no reason why other such project costs could not be recovered through a traditional rate case.

This is not to say that infrastructure costs could never be recovered through a rider. Under the proper circumstances, the Commission may be persuaded that such costs are appropriate for rider treatment. But under the facts presented here, the Commission concludes that Rider QIP is not the proper means to recover the costs in question. AIU's reliance on IAWC's Qualifying Infrastructure Plant Surcharge Rider as support for recovering general infrastructure costs through a rider is misplaced. IAWC's infrastructure rider is the result of specific legislation (Section 9-220.2 of the Act), whereas no such legislation exists for electric utility investment.

Other practical reasons exist for rejecting Rider QIP. As noted above, AIU proposes to pass expenditures related to system modernization and service reliability enhancements through Rider QIP. Plant additions associated with new customers, however, would not qualify for the rider because those projects would produce additional revenue. The problem is that it is not always easy to distinguish the type of project. Some projects may have multiple elements and it is unclear how costs would be recovered if Rider QIP were in place.

Another practical concern is the timeframe for review of proposed expenditures under Rider QIP. AIU proposes that 10 months be allowed for a docket in which Staff and any interveners could participate and weigh in on the costs and benefits of AIU's proposals. Without knowing what/how many projects AIU may seek to pass through Rider QIP, it is difficult to know whether 10 months are appropriate for such a review. Moreover, such additional dockets will increase costs to potential interveners and further drain Commission resources. AIU apparently recognizes the pressure on Commission resources since it has offered to contribute $100,000 to cover the impact on Commission resources as a result of reviewing additional rider filings. Acceptance of this money, the Commission believes, leads to the appearance of impropriety. Furthermore, it is not clear whether AIU would attempt to recover the $100,000 from customers, which would exacerbate the impact of Rider QIP on customers.

With regard to AIU's suggestion that smart grid costs may be recovered through Rider QIP, the Commission is even less comfortable with that idea. While the Commission believes that moving toward a smart grid is appropriate, plans to do so must be well thought out. Before the Commission will consider cost recovery for smart grid improvements, it must be confident that the improvements are practical and cost effective. At this time, it does not appear that AIU is close to having a plan for implementing a smart grid.

Among the concerns expressed about smart grid costs and Rider QIP is AARP's objection to the additional cost burdens that Rider QIP may impose on customers who have no interest in supporting AIU's investment in or ever taking advantage of new smart grid technology for discretionary and non-essential services. AARP also fears that AIU or Ameren may generate unregulated revenue from smart grid investments paid for by customers. AARP seems to suggest that customers should share in such revenue if they are forced to pay for the system enhancements that made the revenue possible.

Another concern regarding smart grid costs and Rider QIP comes from IIEC. While IIEC agrees that smart grid and smart metering may be the delivery service system of the 21st century, it points out that many large industrial customers already have relatively advanced metering installations, whether provided by AIU, by their own investments, or through a retail electric supplier. IIEC fears that Rider QIP could make them pay twice.

Such concerns of AARP, IIEC, and others all must be considered in determining how to implement and pay for smart grid technology. CUB and others recommend that the Commission direct AIU to participate in statewide smart grid workshops to essentially develop a plan for implementing smart grid technology. CUB made a similar, if not the same, proposal with respect to Rider SMP in Docket No. 07-0566. In that docket, the Commission agreed with CUB's proposal, and approved a Statewide Smart Grid Collaborative based on CUB's recommendation but with minor modifications. (See 07-0566 Order at 140-42 (Sept. 10, 2008)) The intent of the 07-0566 Order was for ―the two large investor owned utilities regulated by this Commission" to be involved in a single statewide smart grid collaborative. (Id. at 141) In addition, the 07-0566 Order includes details about the hiring of a facilitator, recovery of costs and the reports that are to be filed. It would be redundant to approve a second smart grid collaborative within this docket, therefore the Commission concurs with CUB's recommendation in this docket and directs AIU to participate in the statewide smart grid workshop, as is established in the 07-0566 Order on pages 140 to 142, under the heading ―Statewide Smart Grid Collaborative." In that section of the Order, the Commission describes the duties, responsibilities and guidelines of the Statewide Smart Grid Collaborative, and as such, the Commission holds that section also applicable to AIU. There may have been certain issues raised in this docket that only apply to AIU; therefore, AIU, Staff, and other interested parties shall also address those in the Statewide Smart Grid Collaborative. Other relevant issues may certainly be addressed as well.

The goal of the Statewide Smart Grid Collaborative is to enable AIU to determine whether a smart grid proposal is feasible for its system and is beneficial. After the Statewide Smart Grid Collaborative is concluded, if AIU chooses to pursue the development of a smart grid, it should file its comprehensive smart grid plan – evaluating costs and benefits – with the Commission for review and approval. In Docket No. 07-0566 the Commission also set forth certain guidelines for such a filing. As the Commission did in the preceding paragraph, it sees no need to restate those guidelines herein, but instead, directs AIU to follow the process already outlined in the 07-0566 Order (under the heading ―Smart Grid Implementation Docket"). Following the conclusion of the Statewide Smart Grid Collaborative, Staff shall timely submit a report to the Commission discussing the outcome of the workshops and making recommendations for further action.

A distinction between this case and the decision in the 07-0566 Order, is that the Commission is not approving a workshop process focused only on advanced meter infrastructure (―AMI"). In 07-0566, ComEd was approved to install AMI in what was identified as Phase 0. Phase 0 included a workshop process to develop project goals, timelines, evaluation criteria and technology selection criteria. Such a workshop is not needed at this time for AIU, since we are not granting approval to AIU to install AMI.

Thus, the Commission agrees with CUB's recommendation for a smart grid collaborative, and directs AIU to participate in the ―Statewide Smart Grid Collaborative" established in the 07-0566 Order and abide by the guidelines outlines in the ―Smart Grid Implementation Docket" in Docket No. 07-0566. The Commission is making the above findings so as to be consistent on this issue between the 07-0566 Order and this docket.

VIII. COST ALLOCATION METHOD

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. Each of the three utilities currently divides retail electric customers into five classes. The DS-1 tariff class contains meter, customer, and delivery charges for residential customers. The DS-2 class presents meter, customer, and delivery charges for non-residential customers with demands up to 150 kilowatt ("kW"). The DS-3 class includes meter, customer, delivery, and transformation charges for non-residential customers with demands of 150 kW-1,000 kW. The DS-4 class includes meter, customer, delivery, transformation, and reactive demand charges for customers with demands exceeding 1,000 kW. The DS-5 class presents fixture charges for lighting customers. The three utilities do not currently have uniform gas delivery classes, but have proposed revisions in this proceeding toward that goal.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a cost of service study ("COSS"). From time to time, however, circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. COSS-Based Rates vs. Across-the-Board Rate Changes

1. AIU's Position

Pursuant to Section 285.5110 of Part 285, AIU included with its rate filing a COSS for gas and electric service. AIU, however, did not follow the results of the class cost of service at equalized class rates of return in determining class revenue requirements. Rather, AIU proposes to equally apply the overall base rate percentage change on an across-the-board basis. For its gas business, AIU agrees with Staff that the across-the-board increase target should exclude Other Revenues and Special Contract Revenues.

In explaining its position, AIU first states that one must understand that rate structures often consist of a combination of both cost of service and other non-cost considerations. AIU indicates that there are numerous non-cost factors that can and do influence rate design such as rate stability and continuity, competition, customer bill impacts, and the current political environment. AIU asserts that these factors may produce rates that vary from class cost of service.

AIU states further that in Docket No. 07-0165, the Commission recognized that AIU electric customers experienced significant bill impacts in 2007 due to the major transition from frozen and reduced, bundled 1997 electric rates to post-2006 rates that included market value prices for power and energy. AIU notes this transition received much attention and resulted in new legislation to mitigate bill impacts to the DS-1 and DS-2 classes. AIU adds that approximately 80% of its gas customers are also electric customers. AIU states that the major impact of the transition in electric rates mentioned above along with the large percentage of combination accounts were major drivers in the decision to distribute the revenue changes in this case on an across-the-board basis. AIU asserts that the Commission‘s Order in Docket No. 07-0165 redesigned electric rates in an effort to mitigate bill impacts, and reflected a movement to a more equitable sharing of the post-2006 rate increase between the residential and the small general service rate classes. According to AIU, the Order effectively required a departure from strict cost-based rates to ―more just and more reasonable rates.” Furthermore, because these electric rates have been in effect for such a short period of time (since January 1, 2008), AIU does not believe that it would be prudent to significantly alter them in this proceeding. AIU states that the circumstances are similar with the demand based rates for the DS-3 and DS-4 classes, which were adjusted by a relatively small amount in October 2007 to reflect implementation of a rate limiter, and its gas rates, which experienced price changes in December 2007.

Additionally, AIU notes that all of its customers (i.e., residential, commercial, and industrial) have seen unprecedented increases in energy bills, gasoline prices, and healthcare costs over the last several years. While rates should track costs, given due consideration to all the factors mentioned above, AIU believes that it is just and reasonable to effectuate across-the-board revenue changes by class in this case. AIU, however, reserves the option to utilize class COSS in future rate proceedings for the allocation of class revenue responsibility.

As suggested above, AIU generally seeks to maintain the existing pricing structure approved in the last delivery service proceeding, as modified by the rate redesign docket. One exception concerns the DS-1 customer, meter, and distribution delivery charges. AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust those charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. AIU understands that Staff and the AG agree with its changes on this issue. AIU, however, generally favors the standardized approach since from an incremental cost perspective, there is very little difference in customer or meter costs among the three.

For the DS-2, DS-3, and DS-4 classes, AIU proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. To the extent there are seasonal (DS-1 and DS-2) or voltage differentiated (DS-3 and DS-4) distribution delivery charges, such charges will be adjusted by a uniform percentage by utility and by class to arrive at the targeted revenue requirement. For the DS-5 class, all fixture and delivery charges are proposed to be adjusted on an equal percentage basis to recover the targeted revenue requirement.

Although Staff expresses some concern with using uniform non-residential customer, meter, transformation, and reactive demand charges among the three utilities, AIU contends that there are numerous benefits to uniform charges. Such benefits include the reduction in oversight by customers and Alternative Retail Electric Suppliers ("ARES") operating in multiple jurisdictions; price consistency which enables consistent decisions by customers concerning transformer, substation, or capacitor bank ownership; and uniform charges reflecting the associated incremental costs. AIU also explains that by using such uniform non-residential charges, it is able to avoid a revenue deficiency that would result under Staff's proposed across-the-board increase to all rate elements. (See AIU Initial Brief at 311-312)

While IIEC does not oppose uniform customer, meter, transformation, and reactive demand charges, AIU notes that it does take issue with increasing those existing charges because it doubts that the underlying replacement cost forming the basis for the charges have increased by a similar amount. AIU explains, however, that the overall revenue recovered from customer and meter charges was tied to the overall customer and meter embedded component cost of service in the previous delivery services rate case, not a replacement cost as suggested by IIEC witness Stephens. AIU states that incremental costs were used to develop voltage differentiated meter and customer charges, and justify uniform charges, but were not used to determine how much revenue to recover from those charges. In this case, AIU says that it was assumed that if the revenue requirement was increasing by 28% for the DS-3 and DS-4 classes, the customer and meter revenue contribution should increase by a similar amount. Moreover, AIU adds, assigning no increase to the customer, meter, transformation, or reactive demand charges would require all of the increase to be assigned to the distribution delivery charge. AIU contends that it is not reasonable to assume that all of the increase in the revenue requirement assigned to a class occurred in the demand-based distribution delivery charge, while the demand-based transformation and reactive demand charges receive no increase. Regarding the transformation and reactive demand charges, AIU state that those services were priced using an incremental cost analysis in the previous delivery services rate case. AIU relates that proposed prices for both of those services are still within the cost ranges provided in the previous delivery services rate case.

With respect to the principles of cost of service rate design, AIU does not disagree with IIEC witness Chalfant's assertions that adhering to cost of service principles promotes equity, engineering efficiency, stability, and conservation. But as indicated above, AIU also recognizes that factors other than cost of service are relevant to determining class revenue requirements. AIU states that it will continue to maintain a long-term commitment to consider rates that reflect cost causation and equitable cost recovery principles as well as other methods for determining class revenue requirements and associated rate design that AIU feels appropriate at the time to present to the Commission.

Ameren Ex. 27.1 presents a comparison of AIU's and IIEC's proposed rates. AIU submits that in all cases the residential class will receive a greater allocation of revenue responsibility under the IIEC proposal. AIU also observes that the large volume delivery service class will receive a lesser allocation of revenue responsibility under the IIEC proposal than the AIU proposal. Additionally, AIU states that one should consider that the delivery component of a residential customer's bill represents approximately 25% to 33% of the bill, while natural gas supply represents the other 67% to 75%. AIU notes that the delivery service component of a large volume non-residential customer typically represents less than 25% of the total bill with the remaining natural gas supply portion representing more than 75%. As a result, AIU states that any proposed distribution service revenue allocation has, on a total bill basis, a greater impact on residential customers and less of an impact on large volume customers. AIU concludes that IIEC's proposal for allocating greater revenue responsibility to the residential class exacerbates this condition. In response to Mr. Chalfant's claim that the future elimination of subsidies will only be more painful if additional subsidies are added in this case, AIU contends that he has not provided any evidence that supports this statement and thus it should be afforded little weight.

With regard to IIEC's recommendation concerning the use of the minimum distribution system ("MDS") concept in allocating costs, AIU agrees that it has theoretical potential, but believes that the issue of implementing MDS is not ripe at the present moment. According to IIEC witness Stowe, MDS recognizes there are delivery service costs directly attributable to electrical industry mandated safety and reliability requirements for distribution facilities, and that do not vary with customer demand. Mr. Stowe contends that those costs should not be allocated on the same basis as demand related distribution system costs. AIU finds Mr. Stowe's analysis flawed because he uses improper data to derive his recommendations. AIU contends further that his analysis unduly relies on safety and reliability concerns as the premise for immediate use of MDS calculations.

AIU asserts that proper development of an MDS-based recommendation requires the use of AIU's specific COSS data, however, Mr. Stowe elects to rely on COSS data from other electric utilities instead. In fact, AIU observes, of the five data sets used by Mr. Stowe, four are from one single conglomerate utility: the Aquila Networks. AIU argues that this choice of data sets and the assumptions made by Mr. Stowe combine to create unusable recommendations. First, AIU maintains that it is fundamentally unsound to use one utility's COSS data to set rates for another utility because each utility has its own distinct set of characteristics that determine what fixed and demand-unrelated costs it faces. AIU points out that the NARUC Electric Utility Allocation Manual ("Manual") relied upon by Mr. Stowe makes this point clear, noting:

> Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the

> climate, the design preferences of management, the planning for the future and the individual power companies that have merged to form the utility. (NARUC Manual at 19)

As Mr. Stowe's data shows, even within a single network, cost allocations for one account may be more than twice as high for one utility than it is for another. AIU compares the 18% demand-related share of FERC Account 366 for Aquila WPK with the 37% share of the FERC account for Aquila L&P. Across utilities from different networks, AIU asserts that variances may be absurdly incomparable – comparing the 82% demand-unrelated share of FERC Account 366 for Aquila WPK with the 6% demand-unrelated share for AmerenUE. AIU states further that the use of averages does not remedy discrepancies when such large variances are involved. At best, AIU contends that use of another, unrelated utility's COSS data might provide a generalization that helps indicate the basic contours of AIU's own cost structure. At worst, however, use of such data to pinpoint the exact division between demand-related and demand-unrelated costs for AIU results in absurdly inaccurate recommendations.

AIU's second complaint is that Mr. Stowe's assumptions are unsupported. According to AIU, Mr. Stowe assumes that his selected data sources – the four Aquila utilities and AmerenUE – represent operations similar to those within the AIU territories. The extreme variations in the data, AIU argues, belie this claim of representative consistency. As Mr. Stowe explains in rebuttal, he also assumes that safety and reliability requirements are necessarily customer-related. Specifically, he states: —This treatment [by AIU, of FERC Accounts 364-367] assumes that the standardized safety and reliability requirements have no effect whatsoever on these costs." (IIEC Ex. 9.0 at 2) AIU asserts that this statement is unsupported and should be disregarded. AIU acknowledges that safety and reliability requirements have an effect on costs, but it does not agree that safety and reliability requirements are necessarily customer related. Mr. Stowe continues: —[F]urthermore, [AIU] incurs these costs for every additional customer it serves, and the costs are independent of customer demand and energy. Ameren recognizes this to be the case and has stated in past cases, as well as in the present case, that the MDS concept has merit." (IIEC Ex. 9.0 at 3) Recognizing that the MDS concept has merit, AIU counters, is not the same as recognizing that costs for minimum safety and reliability standards are independent of customer demand and energy.

Third, AIU argues that the average percentages used by Mr. Stowe to classify distribution plant into customer and demand related categories are thoroughly suspect because the data sets he uses are poor proxies for AIU's cost structure. For instance, AIU states that the Colorado Aquila study took into consideration FERC Accounts 364-368; however, the study Mr. Stowe presents only includes FERC Accounts 364-367. AIU notes further that the data sets used for the Aquila studies are several years old. Finally, AIU observes that Mr. Stowe was unaware of whether the Aquila labor rates reflected in the FERC accounts were the same or different from AIU.

2. Staff's Position

Staff supports increasing existing rates on an equal percentage, across-the-board basis. Staff believes that this approach provides the most consistency with the rates developed in Docket No. 07-0165 to address bill impacts. Moreover, Staff continues, at this juncture there is no evidence to indicate that one group of AIU customers can more easily absorb a greater bill increase than another group of customers. Staff contends that the across-the-board approach appropriately recognizes that bill impacts are the overriding concern for AIU ratepayers in the current period. Furthermore, Staff asserts that it would not make sense to revise the design of AIU's electric rates since less than a year would have passed since the rate design was modified in Docket No. 07-0165. The Commission engaged in that redesign effort to mitigate the unexpected burden on customers and ensuing outrage. Staff does not believe that the concerns of AIU's customers about bill impacts have disappeared and contends that an equal percentage increase would signal to AIU's customers that the impact of higher rates will be equally distributed.

Staff expresses concern, however, that AIU diverges from the across-the-board approach by advocating uniform transformation and reactive demand charges across utilities. Staff is not persuaded by AIU's arguments that uniform charges would reduce the requisite oversight by customers and ARES operating in multiple jurisdictions or promote price consistency that would produce consistent decisions by AIU customers in Illinois concerning owning transformers, substations, and capacitor banks. Because the focus of rate design in this proceeding has been bill impacts, Staff maintains that the means to address those impacts is across-the-board increases of existing rates. Staff does not believe that it would make sense from a consistency standpoint to adopt this across-the-board approach for the large majority of charges while making exceptions for this small set of charges. Additionally, it is difficult for Staff to conceive how the specific exceptions proposed by AIU will benefit the ratemaking process.

One ratemaking proposal that Staff finds acceptable is AIU's recommendation to change the way billing demand is recorded. Currently, charges are based on maximum monthly demands for customers, regardless of when they occur. The new proposal would base maximum demands on the higher of: 1) maximum on peak demands, or 2) 50% of maximum off-peak demands. Staff finds this change reasonable because it will send price signals that encourage usage patterns that save money for AIU and all ratepayers. Staff states that the larger role played by peak demands in determining billing demands will encourage DS-3 and DS-4 customers to shift demands to the off-peak period. According to Staff, any shift in demand will relieve price pressure in the generation market during the peak period when prices should be the highest and also reduce peak period capacity constraints for the delivery system.

Because it advocates an across-the-board approach to revising AIU's rates, Staff does not discuss any concerns with the COSS submitted by AIU. Staff does, however, address the MDS proposed by IIEC. Staff understands Mr. Stowe to argue that there is a minimum cost incurred by any utility when it extends its primary and secondary distribution system, replaces a component on those systems, or connects an additional customer to them. Staff further understands Mr. Stowe to say that the MDS approach classifies and allocates a portion of the distribution system on a customer basis. Staff notes that Mr. Stowe acknowledges that the Commission has consistently rejected the MDS in the past. Contrary to his contention that the Commission's prior experiences with MDS were heavily policy-oriented and theoretical, Staff submits that the Commission has taken a practical approach to MDS by recognizing that the MDS theoretical method of identifying the costs of connecting customers to the distribution system presents problems.

Staff also disagrees with Mr. Stowe's suggestion that the Commission has not previously considered utilities' obligation to comply with safety and reliability criteria when designing distribution systems. According to Mr. Stowe, utilities face significant costs to meet minimum safety and reliability standards for new distribution installations and these costs are clearly customer-related. In particular, Mr. Stowe cites minimum height requirements for distribution wires as well as size requirements for the wires that allow the wire to service more capacity than the customer for whom the system is being extended. Staff notes that he goes on to suggest that the cost incurred to comply with safety and reliability standards begins to outweigh the cost of meeting electrical demand. Staff considers IIEC's position unreasonable and contends that it would be presumptuous to argue that safety and reliability are new concerns for the regulatory process. Staff avers that these issues have existed since the electric industry began. Staff states further that utilities have incurred a variety of costs in the past to meet safety and reliability standards and presumably they will make significant future expenditures in these areas. Staff is not clear why Mr. Stowe considers expenditures on safety and reliability to be information that the Commission has not previously received or considered.

In addition, Staff states that it is difficult to conceive how safety and reliability are related to the number of customers on the system. The premise of the MDS system is that there are costs that pertain to connecting customers to the system, independent of the amount of demand. If the purpose of the distribution system were simply to connect customers, Staff submits that safety and reliability issues would then be a small fraction of their current levels. What creates significant safety and reliability concerns, Staff asserts, is the electricity that courses through the system.

IIEC's position is also flawed, according to Staff, because it identifies a perceived customer component for a distribution system that is clearly related to customer demands. Staff contends that IIEC's logic is comparable to arguing that costs associated with traditional customer-related components of the system, costs such as services and even meters, should be considered demand-related because a large 10 MW industrial customer would require a more costly service line and meter than a smaller customer. Nevertheless, Staff states that the costs of that service line and meter are considered customer-related because their primary purpose is to serve the individual customer. Similarly, Staff adds that the distribution system has the primary purpose of meeting ratepayer demands and is appropriately considered demand-related.

3. AG's Position

The AG agrees with AIU that given the recent attention that the Commission has placed on rate design and cost of service issues for AIU's electric operations, it makes sense to have across-the-board increases in this case. Across-the-board increases, the AG continues, would avoid disparate bill impacts for different types of customers. AG witness Rubin states that a valid COSS is one piece of information the Commission should use in deciding each class's responsibility for any rate increase. But there is other important information that he believes the Commission also should rely on, including customer impact, the overall fairness of the result, rate continuity, gradualism, and other factors. Mr. Rubin contends that AIU's rate design and transition to fully unbundled rates has been exhaustively examined by the Commission over the past two years, and that transition process is still in progress. He maintains that it is reasonable, therefore, for the Commission to decide in this case that any rate increase or decrease should be borne by each customer class in equal proportion to the magnitude of the rate change itself.

The AG opposes IIEC's suggestion that rates be set based on a COSS that incorporates the MDS concept, either in this proceeding or any future proceeding. The AG points out that MDS affects the allocation of a significant amount of plant investment. In this case, the AG reports that IIEC's proposal will shift $54 million in rate base from the commercial and industrial classes to the residential class. For AmerenCILCO, the shift would move more than $16 million in rate base adjustments onto residential customers. This represents 5% of AmerenCILCO's total rate base. For AmerenCIPS, the shift would be $13 million (almost 3% of total rate base), and for AmerenIP the shift would be $25 million (almost 2% of total rate base).

The AG urges the Commission to reject the MDS proposal for various reasons. First, the AG states that IIEC witness Stowe makes several assumptions that are not supported by the evidence, including the submission of an alternative cost analysis that is based on hypothetical information that bears no relation to AIU's service territory. Second, the AG asserts that Mr. Stowe incorrectly assumes that the Commission's treatment of these issues has not been well informed. The AG argues that both of these assumptions are wrong. The AG relates that the Commission has consistently found that there is no customer-related component in these distribution system accounts. According to the AG, Illinois decisions rejecting MDS go back nearly 30 years, and include cases where the utility produced an MDS study that the Commission rejected. Moreover, the AG avers that the Commission's rejection of MDS has not been theoretical or based only on policy, as Mr. Stowe argues, but rather has been based on repeated findings that MDS analyses do not accurately reflect the cost of providing service to customers. (The AG references Docket Nos. 91-0335, 00-0802, and 05-0597 at page 49 of its Reply Brief.)

In response to IIEC's offer of evidence that the MDS exists, the AG states that IIEC simply relies on standards in the NESC that describe minimum standards for the construction of distribution systems. The AG also notes that Mr. Stowe did not actually conduct any analysis comparing the NESC minimum standards to AIU, but instead relied on ―estimated customer and demand percentages" that he alleges are reasonable, based on studies performed for utilities in Missouri, Kansas, and Colorado. The AG asserts that the IIEC analysis is flawed in that it assumes the costs of meeting NESC minimum standards are (i) the same for utilities in different states and (ii) solely related to the number of customers served. In reality, the AG contends that the costs are based on factors completely unrelated to the number of customers served. These factors, the AG states further, are based on the assumption that customers will actually use electricity, causing the consideration of items such as the expected electricity consumption of customers; topography; population density; building type; the proximity of electrical facilities to railways, water and other natural or man-made features, etc. to be important factors.

AG witness Rubin points out that the NESC safety rules for the installation and maintenance of overhead supply lines consist of more than 120 pages and vary based on building height, use of land or water underneath the wires, etc. The AG asserts that IIEC's reliance on these standards is misguided. First, the AG argues that the different systems in Missouri, Kansas, and Colorado that IIEC relies on are not comparable to AIU's system. As an example, the AG states that in Colorado, the NESC standards require additional clearance at higher voltages because these systems are on a higher elevation than AIU's system. Second, the AG reports that there are highly disproportionate ranges for the customer related costs of each utility in the same FERC account; for instance, Account 366 ranges from 18%-94% and Account 367 ranges from 9%-79%. The AG maintains that Mr. Stowe's own data thus absolutely rebuts his testimony that it is reasonable to assume that an MDS study from one utility can be used as a proxy for another utility. Third, the AG alleges that IIEC does not establish that costs associated with satisfying NESC standards are related solely to the number of customers and not to the numerous other factors that affect the construction of distribution facilities. Fourth, the AG contends that IIEC does not establish why any minimum distribution system would be built in the absence of any electrical demand.

4. IIEC's Position

In support of its position that the COSS be used to set rates, IIEC points out that the Commission has recognized the importance of adhering to basic cost of service principles. According to IIEC, the primary reasons for using cost of service as the principal factor in revenue allocation/rate design are equity, cost-causation, appropriate price signals, conservation, and revenue stability. Cost-based rates, IIEC adds, are also essential to the development of competition.

IIEC states that the AIU electric COSS generally follow accepted cost of service principles. IIEC finds the studies to be generally sound and include many of the characteristics of a valid COSS. The studies, IIEC continues, recognize and separately account for the multiple voltage levels at which AIU customers take service. IIEC witness Stowe, however, recommends one significant change to the AIU COSS--incorporation of the MDS concept.

With regard to the AIU gas COSS, IIEC witness Chalfant reviewed those studies and, while he disagrees with the use of the peak and average demand allocator, he does not propose any adjustment to the AIU studies, respecting use of that allocator. He concludes that the COSS demonstrate that industrial customers are subsidizing other AIU customer classes but that the use of the studies for revenue allocation and rate design purposes in these cases is sufficient to move rates toward cost. IIEC contends that the various rationales offered by AIU and Staff in support of an across-the-board approach for gas rates are not sufficient to justify abandonment of cost of service principles. IIEC asserts that AIU's reasons are basically non-cost arguments and many of them are totally unrelated to the provision of natural gas service. Those reasons include: (a) rate stability and continuity; (b) competition; (c) customer bill impact; (d) political environment; (e) AIU's electric rate increase; (f) gasoline prices; and (g) health care costs.

In response to these arguments, IIEC states that AIU has conveniently ignored the fact that rate stability and continuity and competition are enhanced by cost-based rates. Furthermore, IIEC insists that setting rates, as AIU proposes here, on the basis of what is politically correct is neither good public policy nor consistent with the other public policies and legislative priorities, such as the promotion of energy efficiency and demand response. Determining revenue allocations and setting rates on the basis of the increased cost of unrelated products and services, such as gasoline and health care is also not good public policy, according to IIEC. For example, customers who manage their electricity and gas costs through energy efficiency or demand response, possibly achieving savings as a result, may be confused to find their savings diminished by rates changed as a function of the cost of health care or some other product or service unrelated to electricity and natural gas service.

IIEC also suggests that perhaps too much emphasis is placed on rate impacts on DS-1 and DS-2 electric customers and that AIU and Staff have overlooked the fact that these customers have already been the beneficiaries of substantial rate mitigation. IIEC notes that assistance to small electric customers has come in the form of Docket No. 07-0165, Public Act 95-0481, and the Illinois Power Agency's efforts to purchase cheaper power for small customers. Large industrial customers, IIEC points out, are excluded from the benefits of the Illinois Power Agency's efforts.

While utilities normally have no financial stake in the revenue allocation method, IIEC suggests that in this proceeding AIU does; which may be influencing its endorsement of an across-the-board allocation method for electric rates. IIEC notes that AIU is proposing as a rate impact mitigation measure to cap DS-1 rates at an 8.5% increase in overall bundled rates for the first year. Recovery of any remaining allowed increase will begin in the thirteenth month following an order in this proceeding. Using AIU's proposed revenue requirement and across-the-board revenue allocation, IIEC witness Stephens calculates that the voluntary rate cap would cost AmerenIP $31 million. Under AIU's proposed revenue requirement and rates based on a COSS, Mr. Stephens calculates that the voluntary rate cap would cost AmerenIP $67 million. He therefore concludes that use of the across-the-board allocation method allows AIU to recover an additional $36 million under the voluntary rate cap.

IIEC notes that no party to this proceeding elected to present a comprehensive COSS in response to AIU's COSS. Moreover, no party, other than IIEC, offers any critique of AIU's gas or electric COSS. Other than its proposal to modify the AIU electric COSS to include the MDS concept, IIEC contends that there should be no dispute over the appropriateness of the AIU cost studies in this case for allocation of gas and electric revenue requirements and rate design.

With respect to its suggestion to incorporate MDS into the electric COSS, IIEC has provided modified versions of the COSS to reflect the central idea behind the MDS concept. That idea, according to IIEC, is that there are delivery system costs that do not vary with customer demand, but rather are customer related and attributable to electric industry mandated safety and reliability requirements. By definition, the MDS system comprises every distribution component necessary to provide service, i.e., meters, services, secondary and primary wires, poles, substations, etc. The cost of the MDS, however, is only that portion of the total distribution cost the utility must incur to provide service to customers, it does not include costs specifically incurred to meet the peak demand of the customers. Mr. Stowe states that the latter costs are properly allocated on the basis of demand. But unless AIU's COSS are modified to reflect the MDS concept, IIEC maintains that AIU's COSS in this case tend to overstate the cost responsibility of relatively few large customers and understate the cost responsibility of the numerous small customers.

IIEC proposes that its modified versions of the AIU COSS be used for revenue allocation in this case. If, however, the Commission elects not to incorporate the MDS into the AIU electric studies in this proceeding, IIEC recommends that the Commission: (a) use the unmodified versions of the AIU studies for rate design and cost allocation purposes in this case, and (b) direct AIU to incorporate the MDS concept in its next electric delivery service rate case COSS.

In further support of the MDS, Mr. Stowe asserts that to serve customers--even small residential customers -- a utility can not install wires smaller than a certain mandated minimum size or hang wires on poles below a certain height. The applicable minimum size and height requirements are independent of the customer's maximum peak demand or energy usage. Minimum wire size and wire height are mandated by safety and reliability standards which are contained in the NESC. Under these standards, even if existing customer demand increases or decreases, Mr. Stowe testifies that the cost of meeting these NESC standards remains fixed. As an example, Mr. Stowe states that the cost of meeting code requirements for a customer with a peak demand of 3 kW is exactly the same as the cost for meeting the code requirements for a 150 kW or even a 1 MW customer. The components of the system that only just conform to these safety and reliability standards comprise the MDS. The costs of these components represent the MDS costs. At the same time, he continues, if the system is expanded to meet additional peak demands, any costs above those associated with the minimum NESC requirements would be properly allocated on the basis of demand.

The NESC, Mr. Stowe argues, enables simple identification or MDS costs. He points out that the Commission has adopted the NESC standards (See 83 Ill. Adm. Code 305.20(b)), and Illinois utilities must comply with its mandates. The NESC specifies the minimum facilities and construction standards necessary for the safety of the public and utility employees in the installation, operation, or maintenance of electric supply and communication lines or their associated equipment. IIEC asserts that the cost of meeting these standards does not vary with the electrical demands or electrical usage of customers, but will vary based on the number of customers to be served by the electric utility.

In order to modify AIU's COSS to reflect the MDS concept in the absence of AIU specific data, Mr. Stowe used information from MDS studies of four companies which he either personally performed or reviewed during his employment with a public utility. Since the NESC standards apply equally to nearly every electric utility in the nation, Mr. Stowe concluded that it was reasonable to assume that the NESC standards are the same across utility service territories. Based upon this assumption and coupled with his experience in performing MDS studies for public utilities in other jurisdictions, he estimated applicable customer and demand percentages within the range of percentages determined by other utilities with urban operations, suburban operations, and rural operations similar to those of AIU. He also concluded that the total investment in rate base for these utilities was within the range of the total investment for AIU in this case, and that the average mix of primary and secondary distribution, as a percentage of total distribution plant, for his similar utilities was comparable to that of AIU in this case. With the use of these other four utilities' data, he determined the following demand and customer percentages: 84% demand and 16% customer for FERC Account 364 (Poles); 85% demand and 15% customer for FERC Account 365 (Overhead Wires); 39% demand and 61% customer for FERC Account 366 (Conduit); and 26% demand and 74% customer for FERC Account 367 (Underground Conductor). IIEC maintains that using Mr. Stowe's estimates of demand and customer percentages is better than making the de facto assumption that 100% of the subject costs are demand related and 0% are customer related. If the Commission concludes, however, that an Ameren-specific study is required, then IIEC suggests that AIU be directed to perform the necessary studies and present them in the next round of electric delivery service cases.

If the Commission adopts rates based on COSS, yet still has concerns about the impact on customers, IIEC proposes mitigation measures. For electric operations, IIEC offers two alternatives. Under the first alternative, rates for each class would move one-half of the way to cost of service. This approach reduces, but does not fully eliminate, rate subsidies provided or received by each class of customer. The second and final step to cost-based rates could be made in the next AIU electric delivery service rate case or a specified period of time -- e.g., two years after rates take effect. The revenue allocations associated with such an approach for AmerenCILCO, AmerenCIPS, and AmerenIP under the original AIU COSS and IIEC's modified version of the AIU COSS are shown in IIEC Ex. 1.2. Under IIEC's second alternative for electric operations, the Commission could limit the increase to any class' distribution delivery service charges to not more than 25% above the respective utility's overall increase. For example, if AmerenIP were to be granted a 10% overall revenue increase in this case, no customer class would receive an increase greater than 35% (10% + 25%) in its distribution delivery service charges.

In the gas cases, IIEC recommends a revenue allocation that moves rates toward cost of service, but not completely to cost of service. IIEC states that revenue allocation in the gas cases was complicated by the proposed change in class structures for the gas operations of the three utilities. Because of the complications associated with changes in class structures, IIEC proposes a more moderate revenue allocation than suggested by the AIU gas operations COSS. This ensures that customers are not unreasonably impacted by the change in class definition. For AmerenCILCO, IIEC recommends a revenue allocation that still produces a decrease for GDS-1 - Residential (-4.5%), which is approximately the same as the system average decrease (-4.67%), a smaller than average decrease for Rate GDS-5 - Seasonal Delivery Service (-2%), and slightly larger than system average decreases for all of the remaining customer rate classes: GDS-4 (-11%), GDS-3 (-5.90%) and GDS-6 (-11%). For AmerenCIPS Gas, IIEC recommends a larger than average increase for GDS-1 -Residential (26.35%) and GDS-5 - Seasonal Delivery Service (26%) and a smaller than average increase for GDS-2 - Small General Service (17.15%) , GDS-3 -Intermediate General Services and GDS-4 - Large General Service (17.15%). For AmerenIP, IIEC recommends a larger than average percentage increase for GDS-1 - Residential (48%), GDS-3 - Intermediate General Service (48%), and GDS-5 - Seasonal Delivery Services (55%) and smaller than average percentage increases for GDS-2 - Small General Service (37.07%) and GDS-4 - Large General Service (37.24%).

With regard to AIU's proposal to maintain uniformity in certain charges among the three electric utilities, IIEC does not oppose uniform charges per se. IIEC observes that these charges were set on a uniform basis in AIU's last delivery service cases using a combination of embedded costs and replacement or incremental costs. IIEC reports that AIU did not supplant those charges with new cost-based charges. IIEC contends that AIU increases its costs by an escalation factor that is both illogical and unsupported in the record. The proposed charges were escalated on a ratio of the overall increase in delivery service revenues for all three AIU operating companies. According to IIEC, the overall increase ratio of 27% is a function of AIU's proposed revenue allocations and is based on increases to some cost items that have nothing to do with the customer charges, such as electric poles. The escalation factor for the customer charge results in a 27% increase. IIEC argues that there is no basis on which to conclude that the real underlying cost components of the customer charges, as determined in the last AIU delivery service rate cases, have increased by 27% in the two years between the 2004 test year in the last case, and the 2006 test year used in this case. IIEC states that a similar concept holds true for transformation charges and reactive demand charges. In the absence of a valid cost basis for a change in the present customer, meter, transformation, and reactive demand charges, IIEC urges the Commission to retain the current charges.

5. Commercial Group's Position

The Commercial Group endorses the use of AIU's COSS, with the electric COSS modified to reflect the MDS concept. Using AIU's electric COSS, the Commercial Group determined the degree to which certain classes are currently subsidizing other classes. The following table depicts the relative rate of return for each electric class of customers for each utility. The Commercial Group submits that a relative rate of return greater than 1.0 indicates that a customer class is providing subsidies to other classes, while a relative rate of return less than 1.0 indicates that a customer class is receiving subsidies from other classes.

	AmerenCILCO	AmerenCIPS	AmerenIP
DS-1	0.82	0.62	0.26
DS-2	1.39	1.93	2.91
DS-3a	1.76	2.10	1.24
DS-3b	1.86	1.87	2.18
DS-4	0.77	0.59	1.62
DS-5	0.84	1.20	2.38

The Commercial Group argues that all AIU DS-2 and DS-3 customers are currently paying more than their respective cost of service. The Commercial Group also notes that the DS-3 class includes elementary schools while the DS-4 class includes high schools and colleges. The Commercial Group maintains that it is not fair for commercial and industrial customers, schools, and colleges to subsidize other customers.

In addition, the Commercial Group asserts that AIU has an incentive to propose an across-the-board electric rate increase in light of its voluntary rate cap proposal. Mr. Stephens, the Commercial Group states, correctly points out that AIU has a $36 million incentive to propose an across-the-board increase. In effect, AIU's other customers are being asked to help pay for AIU's voluntary rate cap.

The Commercial Group is also under the impression that the Commission, in AIU's last rate case, directed AIU to file rates based on cost in its next rate case:

> [C]ircumstances in this case lead us to believe that no customer class here should subsidize the delivery services rates of another. The

> Commission directs the Ameren companies, in compliance filings, to file tariffs based on cost of service using the NCP allocation method. (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 175)

The Commercial Group states that AIU filed COSS' in this case, although it did not file tariffs based on the COSS'. Mr. Baudino for the Commercial Group reviewed these studies and found them generally reliable for setting class rates.

In response to AIU's comment in its Initial Brief that it worked with the parties in an effort to address their concerns with its across-the-board proposal, the Commercial Group states that it is not sure what AIU means by this remark. The Commercial Group indicates that AIU did not approach it to discuss its concern of having to pay bills that are higher than cost. Nor does the Commercial Group understand AIU's reference in its Initial Brief to higher gasoline prices, higher energy bills, and higher health care costs as reasons for across-the-board rate increases. The Commercial Group asserts that these may be good reasons for keeping AIU's revenue increase as low as possible but not for increasing the subsidization of some classes by others.

The Commercial Group also objects to Staff's proposal for setting rates based on which customer groups can more easily absorb a greater bill increase. It is unclear to the Commercial Group how a class' relative ability to absorb rate increases could be measured in a fair, meaningful, and transparent manner. Regardless of the manner, the Commercial Group maintains that the ability to absorb rate increases (or willingness and ability to organize and advocate) is not a fair, objective way to set rates; cost is the fairest basis for setting rates.

6. Commission Conclusion

In determining whether to adopt an across-the-board rate increase or one based on AIU's COSS, the Commission notes that AIU, Staff, the AG, IIEC, and the Commercial Group have made extensive arguments both for and against the two proposals. Generally, the Commission prefers to set rates as close to the cost of service as is reasonably possible and/or appropriate. To do so, the Commission must first have an accurate idea of what the cost of serving each customer class is in each service area. AIU included with its initial rate filing COSS for its gas and electric operations. Although AIU supports an across-the-board rate increase, its COSS have been entered into the record via the granting of a June 6, 2008 IIEC motion. No party questions the validity of AIU's COSS, although IIEC and the Commercial Group would like the electric COSS to be modified to reflect the MDS concept.

IIEC and the Commercial Group express frustration with the subsidization of smaller customers by larger customers under current electric rates. While they understand the Commission's conclusions in Docket No. 07-0165 that led to the current rate structure, they do not believe that it is fair for larger customers, who are experiencing the same economic uncertainties as smaller customers, to be required to help support smaller customers. The Commission understands this frustration, but in light of the customer impacts that led to the rate redesign in Docket No. 07-0165, finds itself in a difficult situation. Given that the rate design resulting from Docket No. 07-0165 has only been in effect since January 1, 2008, the Commission is reluctant to return to full cost based rates after less than one year. The rate shock that would result from returning to full cost based rates would likely lead to another redesign docket. In order to mitigate the impact of the rate increase approved in this proceeding and avoid renewed rate shock, the Commission believes that it is more appropriate at this time to, generally, increase rates on an across-the-board basis. The Commission certainly does not mean to suggest by this decision that cost based rates have fallen out of favor. Indeed, cost based rates, as we affirmed in our recent decision in Docket No. 07-0566, continue to be the Commission's preferred rate design methodology. That said, for purposes of this proceeding and based on this record the Commission concludes that adoption of an across-the-board increase is the most prudent and reasonable methodology that will serve to ease rate impacts occurring due to the continued transition from the end of the rate freeze.

Since the Commission is not adopting rates based on AIU's COSS, it need not address the proposal that the COSS be revised to reflect the MDS concept. Nevertheless, the Commission feels compelled to mention that using cost data from other utilities and applying that data to AIU, as IIEC does, is of little value to the Commission. As noted by AIU and other parties, significant differences exist between AIU and certain of the utilities that IIEC chose to use data from and apply to AIU. As for requiring AIU to submit COSS incorporating MDS in its next rate cases, the Commission notes AIU's objection that it not be required to do so unless the Commission intends to adopt the MDS concept in setting rates. While IIEC's discussion of the MDS concept presented some interesting ideas to consider, the Commission is not prepared to conclude here that it will implement MDS in AIU's next rate cases. Therefore, the Commission will not require ratepayers to pay the cost of preparing a COSS incorporating the MDS concept for AIU's next rate cases. This does not mean to suggest, however, that other parties should not feel free to propose COSS reflecting the MDS concept.

As noted above, AIU determined that for the purposes of this proceeding to no longer seek uniformity and instead agreed to adjust the DS-1 customer, meter, and distribution delivery charges by a level equal to the average change in residential delivery service revenue for each of the three utilities. The Commission understands that Staff and the AG agree with the changes on this issue. The Commission finds AIU's proposal regarding DS-1 reasonable and approves it. In the future, however, the Commission will be interested in returning to uniform customer, meter, and distribution delivery charges among the customers of the three utilities to the extent that doing so is prudent.

For the DS-2, DS-3, and DS-4 classes, AIU also proposes to maintain uniform meter and customer charges across the three utilities. AIU also proposes to maintain uniform transformation (for both DS-3 and DS-4) and reactive demand (DS-4 only) charges. AIU states that the distribution delivery charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. AIU believes that this proposal will facilitate service to customers, or potential customers, taking electric service from more than one of the utilities. The Commission recognizes that there are objections to at least portions of this AIU proposal, but nevertheless finds it reasonable and agrees that it will likely facilitate service to larger customers. The Commission therefore approves this AIU proposal.

With regard to the Commercial Group's citation to page 175 of the Order in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and its discussion of cost based rates, it appears that the Commercial Group misunderstands what is meant by a compliance filing. The compliance filing in that context referred to AIU's tariffs implementing the conclusions in that Order and filed within days of the entry of that Order. The language cited by the Commercial Group was not referring to AIU's next rate cases.

B. COSS in Next Rate Cases

Staff recommends that AIU propose gas and electric rates in the next rate cases based on cost of service. AIU does not object to doing so but indicates that it may also propose rates using an across-the-board approach or some other hybrid method. AIU explains that it wishes to preserve its options in case it does not believe, under the circumstances in the next cases, that strict adherence to cost of service is appropriate. Staff agrees that there is no way of predicting the future and what conditions may exist, and understands AIU's caveat to leave its options open to an alternative rate design dependent on future conditions. IIEC and the Commercial Group support the filing of COSS in AIU's next rate cases, but add that the electric COSS should incorporate the MDS concept. LGI recommends that AIU's next rate filings include a detailed COSS showing a lighting cost of service analysis for AIU identifying lighting fixture costs as well as a detailed street light rate design study to determine cost-based lighting fixture charges. If AIU is to file new COSS in its next rate cases, Grain and Feed Association of Illinois (“GFA”) would like the studies to evaluate and address the characteristics of seasonal users in general and, in particular, grain dryers. AIU objects to conducting studies incorporating GFA's proposal.

AIU is already required to provide a COSS for each utility pursuant to Part 285. The Commission anticipates that AIU will comply with this requirement and provide COSS in its next rate case filings. The Commission finds value in Staff‘s recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases. In considering a move towards rates based on the cost of service, AIU should take into account alternative rate structures for the all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. Market-based dynamic prices may have the overall effect of reducing the electric bills of all-electric classes of customers while at the same time ending the explicit subsidy that was designed to accomplish the same end. (See Docket No. 07-0165, Order at 25-28 (Oct. 11, 2007); see generally, Order on Rehearing (Oct. 29, 2007). In times of rapidly rising energy costs, the Commission needs to be able to consider all options available to it to restrain rate shock while simultaneously setting rates as close as possible to cost. An analysis of the effect of dynamic market-based prices for the all-electric sub-class of residential customers would give the Commission valuable insight as to its potential benefits as the utility tries to meet those important, and some times mutually exclusive, objectives in the next rate case. In its cost of service analysis, AIU's electric utilities should develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial. Whether AIU proposes alternative rates based on some other approach is up to AIU for the reasons discussed above. However, having cost-based rates with which to compare against alternative approaches will be instructive. As noted earlier, the Commission will not be requiring AIU to incorporate the MDS concept in its next electric COSS. The Commission will, however, require AIU to analyze the cost of lighting service in each of the utility's electric service areas and develop cost-based rates for lighting fixture charges, as proposed by LGI. AIU shall also analyze the cost of serving seasonal gas users as proposed by GFA. The arguments of LGI and GFA both give the Commission reason to further consider their respective positions. AIU's rate filings, however, need not reflect adoption of the lighting and seasonal user analyses. These analyses simply need to be available for the parties and Commission to consider.

IX. RATE DESIGN/TARIFFS TERMS AND CONDITIONS

The above discussion on how to allocate costs among the classes of electric and gas customers is but one component of rate design. Rate design, in the parlance of the Commission, also encompasses the terms and conditions of service in a utility's tariffs. Over the course of this proceeding, parties raised several issues and presented arguments concerning the terms and conditions of service. Some of these issues have been resolved, while others remain contested.

A. Resolved Gas and Electric Issues

1. Budget Billing Plan Tariffs

Staff witness Harden recommended that AIU provide more specific language concerning the methodology used in its budget billing plan regarding over or under recovery of customer revenue. In response, AIU witness Jones proposed revised language that (a) reinstates the ―annual settle-up" (i.e., lump-sum settlement) language in existing tariffs and (b) provides flexibility for AIU to offer a second choice to customers to smooth any annual settlement amount over the next 12 months. Ms. Harden agrees with AIU's revised language for both the gas and electric tariffs. The Commission finds the revised language appropriate and directs that it be used.

2. Refundable Deposits for Line Extensions

Staff witness Lounsberry raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Gas Service. He believed that the language could be interpreted in a manner inconsistent with 83 Ill. Adm. Code 500, "Standards of Service for Gas Utilities." In response to Staff data request ENG 2.202, AIU witness Warwick provided alternative language alleviating Mr. Lounsberry's concerns. The Commission finds the alternative language reasonable and directs that it be used.

Similarly, Staff witness Rockrohr raised a concern regarding AIU's proposed tariff language concerning refundable deposits under AIU's Standards and Qualifications for Electric Service. He believed that the language could be interpreted to mean that AIU would have sole discretion to determine the period of time over which an applicant who makes a refundable deposit would qualify for a refund, which is contrary to Section 410.410. In response, AIU witness Jones provided alternative language clarifying that customers will always have a cash deposit option available. This language is acceptable to Mr. Rockrohr. The Commission concurs and directs that the alternative language be used in AIU's compliance filing.

B. Resolved Gas Issues

1. Uniform Gas Tariff Language

AIU submitted an entirely new tariff book for each of the three gas utilities. Many of the terms and condition are the same as those in the existing tariffs, but have been written/presented differently in order to make the three companies' tariffs more uniform. AIU describes the proposed changes in its Initial Brief at pages 324 through 327. Staff agrees that creating more uniform gas tariffs is desirable and recommends that the Commission approve the revisions. The Commission concurs and directs AIU to reflect the changes in its compliance filings in this proceeding.

2. Renaming of Certain Gas Customer Classes

AIU proposes to rename its gas customer classes as follows in order to conform to its electric customer classes:

AmerenCILCO

Present Rate Classification	Proposed
Rate 510 – Residential Gas Service	GDS-1
Rate 550 – Small General Gas Service	GDS-2
Rate 600 – General Gas Service	GDS-3
Rate 600 – Minimal Winter Use Gas Service	GDS-5
Rate 650 – Intermediate General Gas Service	GDS-4

Rate 700 – Large General Gas Service	GDS-6
Rate 800 – Contract Service	GDS-7

AmerenCIPS and AmerenCIPS Metro-East

Present Rate Classification	Proposed
Rate 1 – Residential Service	GDS-1
Rate 2 – General Delivery Service (small meter < 700 cubic feet per hour ("cfh"))	GDS-2
Rate 2 – General Delivery Service (large meter > 700 cfh)	GDS-3
Rate 3 – Large Use Firm Delivery Service	GDS-4
Rate 3 – Minimal Winter Use Delivery Service	GDS-5
Rate 4 – Large Use Inadequate Capacity Delivery Service	GDS-4
Rate 4 – Minimal Winter Use Delivery Service	GDS-5
Rate 5 – Special Contract Service	GDS-7

AmerenIP

Present Rate Classification	Proposed
Rate 51 – Residential Gas Service	GDS-1
Rate 63 – Small Volume Firm Gas Service	GDS-2
Rate 64 – Intermediate Volume Firm Gas Service	GDS-3
Rate 65 – Large Volume Firm Gas Service	GDS-4
Rate 66 – Seasonal Gas Service	GDS-5
Rate 76 – Transportation of Customer Owned Gas Service	GDS-1-5
Rate 90 – Contract Service	GDS-7

Staff accepts the proposed renaming of the gas customer classes as long as it does not result in unequal bill impacts on individual gas customers. The Commission finds the proposal to rename the customer classes reasonable and is aware of no unequal bill impact on any customers; therefore the renaming of the classes should be reflected in the compliance filings.

3. Customer Charges and Metering Differentials

AIU initially proposed to change all customer charges by an across-the-board percentage except the differential between the customer charges for sales customers and the customer charges for transportation customers that accounts for the added costs of daily metering. AIU's proposal also included the requirement of daily metering service and the imposition of such a differential for the first time for AmerenCILCO's Rider T customers. Staff witnesses Sackett and Harden objected to the exceptions to the across-the-board change. Mr. Sackett testified that the disproportionate changes would be a barrier to transportation customers. Ms. Harden objected because the proposal deviates from the across-the-board change and would cause a higher level of bill impacts for transportation customers. AIU witness Warwick accepted this, removed the AmerenCILCO differential, and changed the customer charges for each Local Distribution Company (―LDC") by the across-the-board percentage. Staff finds these changes acceptable and the Commission concurs with these changes. The resolution of this issue between AIU and Staff should be reflected in AIU's compliance filing to the extent not otherwise affected by the conclusions below.

4. Use of PGA in Cashout Mechanisms

Initially, AIU proposed to cashout daily imbalances between nominations and usage for gas transportation customers at the higher of the Chicago City gate price or the PGA and monthly imbalances at the higher of the Average Chicago City gate price or the PGA. Staff witness Sackett objected to this because the Chicago City gate price reflects the market and no other major LDCs in Illinois have the PGA in their cashout mechanism. AIU witness Glaeser removed the proposal. The current proposal is for the Chicago City gate to be the only daily cashout price. AIU has also removed its proposal for a monthly cashout. Staff agrees with this proposal. CNE-Gas supports these changes as well. The Commission finds the cashout mechanism acceptable and directs that it reflected in the compliance filing.

5. Curtailment Language

Staff identified a drafting error regarding the proposed Curtailment Plan – wherein transportation customers were to be completely curtailed before any system supply customer. AIU addressed this error and indicates that it is not its intent to confiscate gas supply from a transportation customer and supply it to a PGA customer of the same type in the event of a system curtailment. AIU states that curtailments will take place on a customer service level and not by the type of service (Rider T or Rider S) the customer is utilizing.

Staff also recommended that AIU adopt a blend of the current AmerenCILCO and AmerenIP curtailment plans. AIU contends that doing so is not feasible. AIU witness Glaeser explained that the Curtailment Plan would only be initiated in the most severe circumstances when it is imperative that customers reduce load to enable AIU to serve the residential customers and human need providers. AIU stated that Staff's recommendation is a complicated scheme that would not be workable in an expeditious manner during a system emergency. Staff later accepted AIU's explanation.

In response to CNE-Gas' comment that AIU should only curtail deliveries within a particular customer class, without regard to whether a customer is a firm transportation or firm sales customer, AIU stated that this is exactly how the Curtailment Plan is written and intended to operate. Mr. Glaeser explained that the first category of Curtailment is ―Category 1: Customers taking service under Rates GBS-4, 5, 6, and 7 except those Customers identified under Category 3" and that the curtailment language is defined by rate category and, again, not whether the customer is taking service under Rider T or Rider S.

Staff witness Sackett objected further to AIU's proposed curtailment language because although AIU provided a rationale for four of the reasons that a Critical Day may be declared, it also added a fifth —catch-all” reason. Initially, AIU had proposed to add language under Rider T to allow the declaration of a Critical Day for any —other market condition which may warrant such action by [AIU].” Later, Mr. Glaeser offered to revise the language under the Critical Day definition to reflect the purpose of declaring a Critical Day. The Critical Day definition was revised by removing —market” prior to —conditions” and qualifying that action may only be taken due to conditions which —jeopardize the system integrity and/or system reliability.” Staff found this change acceptable.

The Commission finds the resolution of the curtailment language issues reasonable and directs that AIU's compliance filing reflect the resolution.

6. Small Volumetric Distribution Charge

AIU recommended eliminating the Small Volumetric Distribution Charges for AmerenCILCO GDS-4 and GDS-6, and AmerenIP GDS-4. Staff witness Harden did not agree with this due to the unequal bill impacts for individual gas customers that could result from this change. AIU has agreed to maintain the Small Volumetric Distribution Charge for these rate classes. The Commission concurs that doing so is appropriate.

7. Standard Information Provided with Customer Usage History

In response to an issue raised by CNE-Gas, AIU agrees to provide with usage history requests (a) the customer's service classification and rider(s), (b) the customer's maximum daily contract quantity, (c) if applicable, the customer's bank volume, and (d) if applicable, the customer's gas main maximum allowable operating pressure. The Commission finds that doing so is reasonable and directs provisioning of this information be reflected in AIU's compliance filings.

8. Reconnect Charge

AIU witness Warwick proposes to set the gas Reconnect Charge at $15.00 during regular working hours and at $50.00 outside of regular working hours for each of the three utilities. The Reconnect Charge is currently $55.00 during regular working hours and $100 outside of regular working hours at AmerenCIPS, $25 or actual cost at AmerenCILCO, and $15.00 during regular working hours and $25 outside of regular working hours for AmerenIP. Staff recommends approval of the uniform Reconnect Charge changes as a reasonable change. The Commission concurs and approves the change.

9. Dishonored Check Charge

AIU witness Warwick proposes to set the Dishonored Check Charge at $15.00 for each of the three utilities on any negotiable instrument returned by a bank, savings institution, or other institution. The Dishonored Check Charge is currently $15.00 at AmerenCIPS and $10.00 at AmerenCILCO and AmerenIP. Staff recommends approval of the uniform Dishonored Check Charge change, noting that it is below the charge at many other Illinois utilities. The Commission finds the $15.00 Dishonored Check Charge reasonable and approves of the change.

10. Footage Allowance for Service Connections

AIU witness Warwick proposes to conform all of AIU's gas tariff language regarding allowances for service connections to the language contained in the Joint Agreement of the Parties, attached as the Appendix to the Commission‘s Order in Docket No. 03-0767. In that proceeding, all parties reached an agreement that the free footage allowance for service connections in Illinois should be 60 feet of gas pipe. Staff witness Harden finds AIU's proposal acceptable. Consistent with its findings in Docket No. 03-0767, the Commission approves of this change.

11. Group Balancing Service for AmerenCILCO

AIU witness Glaeser explains that a key provision in the proposed services allows for Group Balancing under Rider G, which is a new service for transportation customers on the AmerenCILCO system. Group Balancing is already available to AmerenIP and AmerenCIPS transportation customers. The service provides the transportation customer and/or its marketer with an opportunity to request that its accounts be combined with two or more accounts on the same interstate pipeline for nominating and balancing purposes. Transportation customers located in a city that is served by multiple interstate pipelines, as identified on the AIU web page under Unbundled Services Management System ("USMS"), will be allowed to balance nominations across those specific multiple pipelines. Additionally, this service allows the Group Manager to manage a group of customer accounts as a single load rather than by individual accounts, and provides a netting mechanism for mitigating imbalances, wherein the daily over-deliveries for one customer can offset the under-deliveries for another customer. This offsetting arrangement aids the Group Manager in keeping daily imbalances to a minimum. The larger the marketer‘s customer group becomes under Group Balancing, the greater the netting effect which improves daily imbalance performance. The Commission considers the provisioning of Group Balancing for AmerenCILCO transportation customers appropriate and approves of its implementation.

12. Consolidation of PGA Rates

AIU witness Glaeser proposes that the AmerenCIPS PGA and the AmerenCIPS Metro-East PGA be consolidated into a single PGA rate. According to Mr. Glaeser, natural gas prices have been more volatile since the winter of 2000-2001. If consolidated, he states that the AmerenCIPS Metro-East customers would be part of a larger service area and a more stable PGA rate could be provided because of expanded hedging opportunities. Mr. Glaeser explains that the AmerenCIPS strategy is to have approximately 60-75% of a normal winter‘s demand hedged through a combination of price hedge protection and storage withdrawals. He asserts that this strategy works well in a large system that has a large number of baseload transactions that can be efficiently price hedged. This same strategy, however, becomes constrained in a small system with limited baseload transactions where one or two hedging transactions determine the PGA for the entire winter heating season. Mr. Glaeser further testifies that if the Commission grants this proposal, AIU would be willing to work with Staff to develop a mechanism to ensure that the AmerenCIPS and AmerenCIPS Metro-East customers would be charged or credited with respect to the balance of any over- or under-recovered costs existing at the implementation date.

Based on these potential benefits to AmerenCIPS Metro-East customers, and given Mr. Glaeser‘s agreement to work with Staff while converting to a single PGA rate, Staff does not oppose the consolidation of the AmerenCIPS and AmerenCIPS Metro-East PGA rates into a single PGA rate. If the Commission approves AIU's proposal to consolidate the PGAs, Staff recommends that the Commission order AmerenCIPS to submit a monthly report to the Commission‘s Bureau of Public Utilities, for one year following the date of the order in this proceeding, estimating the PGA rates applicable to AmerenCIPS and the AmerenCIPS Metro-East territory as if no consolidation had been approved. AIU does not object to submission of monthly report as described by Staff. The Commission finds the proposals reasonable and directs that they be reflected in AmerenCIPS' compliance filing.

13. Ameren CIPS Rate 2

For AmerenCIPS and AmerenCIPS Metro-East, AIU witness Warwick proposes splitting existing Rate 2 -General Delivery Service into two new rate classes: GDS-2, for small meters (Meter A) and usage less than 700 cfh, and GDS-3, for large meters (Meter B) and usage greater than 700 cfh. Staff witness Harden does not oppose this proposal since it would not result in unequal bill impacts for individual gas customers. The Commission finds the proposal reasonable and approves it.

14. AmerenCIPS Rate 4

AIU inadvertently omitted certain tariff language it had intended to retain from the current AmerenCIPS Rate 4 – Inadequate Capacity System Gas Service. The language is currently in the existing AmerenCIPS tariff and it is appropriate to maintain the same language in the proposed tariffs related to this case. Staff supports the revision of the tariff to include the language in question. The Commission concurs with the revised language and directs that it be used.

15. AmerenIP Service Activation Fee

AIU witness Warwick proposes to eliminate the gas Service Activation Fee for AmerenIP, as neither AmerenCIPS nor AmerenCILCO have a similar provision. AmerenIP's Service Activation Fee is $10.00 when a customer requests service under Service Classifications 51, 63, or 64. If the service activation requires lighting, relighting, or inspection of appliances, the charge is $25.00. Since AmerenIP has not shown a need for the charge and since AIU is focusing on uniformity in the instant proceeding, Staff witness Harden agrees with AIU that elimination of the Service Activation Fee from AmerenIP's tariffs is appropriate. The Commission concurs and directs that this change be reflected in AmerenIP's compliance filing.

16. AmerenIP Rates 4 and 5

AIU witness Warwick proposed to eliminate the AmerenIP Facilities Charge presently in Rates 65 and 66. Staff witness Harden initially opposed this change and proposed that an across-the-board increase be applied to each rate without eliminating any individual rate elements, because unequal bill impacts may occur. In response, Mr. Warwick stated that this proposed revision would not result in unequal customer bill impacts. To further the argument, he presented an example calculation in which he increased the Facilities Charges by the overall percentage increase, with some rounding, and then merged the resulting charge into the proposed Customer Charges. In the example, the resulting value is the same whether the Facilities Charge is a separate charge or rolled up with the Customer Charge. Therefore, there is not an unequal bill impact. AIU contended that the resulting charge becomes more straightforward to the customer by eliminating unnecessary line item charges. AIU stated further that this is another area where it can move towards tariff conformance with no adverse customer impact. Staff agreed to merge the AmerenIP Facilities Charges for GDS-4, GDS-5, and Rider T into the applicable Customer Charges. The Commission approves of this proposal.

17. Elimination of AmerenIP's Rider H

AmerenIP proposes to eliminate its Rider H – Adjustment for Pipeline Transition Surcharge since it has not been used in several years. Staff witness Harden agrees that Rider H should be eliminated from the AmerenIP tariffs. The Commission finds this proposal reasonable and approves it.

C. Resolved Electric Issues

1. Customer and Meter Charge

AIU has a three-part residential electric rate consisting of a customer charge, a meter charge, and a distribution charge. The current customer charge and meter charge are the same among the three utilities. AIU had initially proposed to increase the customer and meter charges by 27% for all three, which is AIU's proposed system-wide approximate average increase. Because of the impact on residential bills, the AG and Staff objected to AIU's proposal and recommended that AIU at least temporarily abandon the notion of uniform customer and meter charges. AIU now agrees and favors an approach similar to that of the AG and Staff. Pursuant to this approach, AIU will increase customer and meter charges by a level equal to the average change in residential delivery service revenue for each of the three electric utilities. The Commission finds that the AG and Staff approach is reasonable for purposes of this proceeding and approves it, however, the Commission directs AIU and Staff to review the issue of uniform customer and meter charges among the three utilities in their next electric rate cases.

2. Supply Cost Adjustments

The components that make up AIU's Supply Cost Adjustment (–SCA") are as follows: the Supply Procurement Adjustment, an Uncollectibles Adjustment, and a cash working capital adjustment. The Commission has directed AIU to update these costs and/or factors in delivery services rate case proceedings.

a. Supply Procurement Adjustment Amortization Period

AIU states that the Supply Procurement Adjustment is intended to compensate each utility for all direct and indirect costs of procuring and administering power and energy supply for all customers, other than amounts recovered in other charges to customers receiving power and energy service from AIU. According to AIU, these costs consist of expenses such as professional fees, costs of engineering, supervision, insurance, payments for injury and damage awards, taxes, licenses, and any other A&G expense not already included in the cost of power and energy service.

AIU and Staff agree that the correct ongoing costs to be recovered through the Supply Procurement Adjustment is $1,057,003 and the amount to be amortized over the life of these rates is $1,415,011. AIU states that it and Staff agree on the amount of the adjustment, and agree that the amortization period for the amortized portion of the costs should be consistent with the amortization period approved by the Commission in this case for electric rate case expense. AIU says the parties only disagree with whether such amortization should be based on two years or three years.

The Commission has determined the amortization period for rate case expense elsewhere in this Order. It appears that there is no other decision that the Commission must make with regard to this issue.

b. Uncollectible Adjustment

AIU witness Jones presented a chart in direct testimony showing proposed Uncollectibles Adjustment factors by rate class, which are a subset of the SCA contained within Rider PER (AIU's tariff governing prices and cost recovery for fixed price power supply service). Staff witness Ebrey objects to a portion of the calculation proposed by AIU pertaining to write-offs for combination (both gas and electric) customers, and recommends that write-offs be allocated based on the relative gas versus electric revenues for combination customers. AIU adjusted its methodology for development of the class specific uncollectibles factors based on Ms. Ebrey's recommendation in her rebuttal testimony, and thus the issue is no longer contested. AIU states that now, only the total level of uncollectible account expense is at issue. The updated Uncollectibles Adjustment factors, taking into account the adjustment proposed by Ms. Ebrey and the total level of uncollectible account expense proposed by Mr. Stafford, are presented in AIU's Initial Brief. AIU says that if the Commission approves overall uncollectibles rates different from those provided in Mr. Stafford's rebuttal, the class level uncollectibles factors should be updated to match the approved overall uncollectibles rate.

The Commission has determined the uncollectibles issue elsewhere in this Order. AIU is directed to update the uncollectibles factors consistent with the Commission's conclusions when it makes its compliance filing at the conclusion of this proceeding. Based upon the Commission's decision to adopt AIU's three-year average for uncollectibles, the approved uncollectibles factor for AmerenCILCO is 0.582%, for AmerenCIPS is 0.569%, and for AmerenIP is 0.541% as shown on Ameren Ex. 19.4.

c. CWC Adjustment

According to AIU, the purpose of the CWC Adjustment is the equitable recovery of the time value of expenses incurred to purchase power and energy for customers in a manner that recognizes the time lag between the incurrence of these expenses and the revenue stream or receipts from customers who pay for said power and energy. AIU's proposed CWC Adjustment is 0.7986%, which has increased from 0.308%.

AIU claims the CWC associated with the power supply should be based on the calculations shown on Ameren Ex. 3.16E for each of the utilities. As discussed above in this Order, Staff witness Kahle recommends that AIU receive preferential treatment on the timing of payments from affiliated companies, in order to offset the shorter lead time in which AIU has to pay suppliers for electricity purchases, due to AIU's current credit situation. AIU argues that Mr. Kahle's position should be rejected because it conflicts with the Commission's rules designed to protect against preferential treatment between affiliated companies.

The Commission has made its decision regarding CWC elsewhere in this Order. When it makes its compliance filing at the conclusion of this proceeding, AIU is directed to make any changes to its SCA to reflect the Commission's decision regarding CWC. The Commission approves a CWC Adjustment factor of 0.7986% for use in Rider PER.

D. Contested Gas Issues

1. Gas Bank Sizing and Daily Balancing Tolerances

a. AIU's Position

In an effort to bring standardization and uniformity to gas transportation services across the three utilities, AIU has requested approval to unite all transportation services into one new rider, Rider T--Gas Transportation Service, applicable to each utility. In the process of reforming the transportation services to bring about standardization, AIU has also updated the tariffs to meet modern system goals and requirements. Central to the Rider T proposal are the policies presented with regard to banking services and imbalance tolerances designed by AIU to meet the necessities of modern operating and market conditions.

i. Policy Considerations

To understand the relevance of its banking services proposal, AIU points to the policy drivers behind the banking services and imbalance tolerance provisions, and the overall context of banking services within the Rider T framework. AIU asserts that the need for modified banking services and tolerance levels is driven by:

- Gas price volatility, which exacerbates the potential gaming opportunities and unduly exposes sales customers to cost transfers;
- Pipeline tariff restrictions, which limit the gas utilities' flexibility; and
- Pipeline capacity constraints, which means there is not the means by which to access additional gas supply.

AIU asserts that extreme price volatility in the North American natural gas markets since the winter of 2000/2001 and growing interstate pipeline capacity constraints have fundamentally changed the nature of the natural gas industry. AIU contends that the flexible transportation services it currently offers were developed years ago during a period of stable gas prices and excess and unconstrained interstate pipeline capacity in the Midwest, conditions that no longer exist today. Certain of AIU's existing transportation services include monthly balancing. AIU asserts that monthly balancing was acceptable when gas prices were stable at $2 per MMBtu for years on end, but becomes very problematic when gas prices swing up to $1 per MMBtu from day to day and can reach $14 per MMBtu during peak periods.

Monthly balancing, AIU continues, creates opportunities for gas suppliers to exploit short-term price swings. AIU explains that monthly balancing in volatile gas markets gives transporters and marketers an incentive to —short” (under-deliver gas supply compared to customer demand) the LDC system on days when gas prices spike to high levels and —go long” (over deliver gas supply compared to customer demand) on days when gas prices drop to low levels, while staying roughly in balance by the end of the month. AIU witness Glaeser testifies that this manner of market arbitrage raises

AIU's costs. Since the transportation customer‘s demand still exists while its marketer is —shorting” the system, he explains that the LDC must still meet the overall demand of the system by delivering additional gas supplies from its suppliers and withdrawing additional gas from leased and on-system storage resources. In other words, the LDC must purchase additional gas supplies at potentially higher market prices to make up for marketers —shorting” the system. This in turn, Mr. Glaeser reports, may directly impact the sales customers, since the cost of the incremental supplies and storage withdrawals are included in the PGA rates which are paid for by the sales customers and not the transportation customers or their marketers. The inverse situation is also problematic, where daily gas prices drop to low levels and a marketer will —going-long” or over-deliver compared to its customer‘s demand which, in turn, makes less room for the LDC to acquire gas supply during low priced periods which would lower the PGA rate. This type of operational behavior is permissible under the current tariffs for AmerenCILCO and AmerenIP, which AIU contends is the fundamental reason for the proposed changes.

With regard to capacity constraints, AIU indicates that most of the interstate pipelines that it operates on are now constrained in that all or most available firm capacity is under contract with shippers and the utilization of that firm capacity has increased, especially during the summer period for gas-fired power generation. Since 1999, AIU reports that approximately 200,000 MW of gas-fired generation has been built in the U.S. which has a potential demand of 17 Bcf/day compared to the production of natural gas in the lower 48 states of 51 Bcf/day. AIU asserts that this new demand has created significant stress on interstate pipeline operations and has given greater exposure of the natural gas markets to the price volatility of the power markets. Mr. Glaeser also testifies that even in the last 18-24 months there has been a substantial increase in pipelines issuing operational flow orders ("OFO") and system protection warnings.

AIU asserts that one of the contributing factors to the current system integrity issues is the increased reliance on natural gas used for electricity production. Ameren Exhibit 30.1 graphically demonstrates the significant amount of natural gas being consumed by power generation. AIU states that gas-fired generation has the potential of creating near instantaneous peak day demands on the pipeline systems during the summer season, which directly competes for gas supply and capacity for storage injections. AIU contends that this is causing interstate pipelines to operate with tighter tolerances, which are reflected in their tariffs for services such as daily balancing, imbalance cashouts, and penalties, in addition to operational constraints such as interruptible transportation curtailments and pipelines not allowing secondary-out-of-path nominations. AIU states that the demand for natural gas by the power generation sector has become a major source of demand for the gas industry and has created significant competition for natural gas during the summer when gas supply and pipeline capacity for storage injections are critical. In other words, the gas industry has been transformed from a winter peaking industry to a winter and summer peaking industry which has contributed to increased price volatility and constrained pipeline capacity. AIU reports that its own experience with gas generation supports this contention.

Ameren Ex. 30.3 is a graph of AmerenUE's gas generation demand since 2004 which has shown sharply increasing gas demand each year, which even outstripped the utility's internal budget forecasts. In 2004, AmerenUE's gas generation demand was 758,000 MMBtu which by 2007 had risen to 10,494,000 MMBtu or by 1,400%.

AIU submits its transportation tariffs have not changed or adapted to the new operating environment. To eliminate or at least reduce the possibility of marketers exploiting existing balancing services, AIU's proposed transportation tariffs have been designed to maintain tighter system operations in order to protect system integrity and mitigate the impact of gas price volatility on the sales customers. Of AIU's 817,000 total customers, all but 518 are system sales customers. The 518 transportation customers, however, represent a significant level of system throughput. In addition, this is the first real opportunity for AIU to update transportation services to meet the challenges of today's natural gas markets and to develop common transportation services since the acquisition of CILCO in 2003 and IP in late 2004.

To manage such tight interstate pipeline tolerances, AIU contracts for and maintains a portfolio of resources on the interstate pipelines. These resources include services offered by the interstate pipelines such as no-notice storage service, park and loan service, line pack service and park/unpark service, point operator agreements, and operational balancing agreements. These services effectively provide AIU with additional balancing flexibility and banking ability to operate within very tight tolerances. AIU points out that sales customers pay for these services.

Staff witness Sackett disputes AIU's position that interstate pipelines are operating with tighter tolerances since 1999 (when a significant amount of gas-fired generation was built in the U.S.); he further states that AIU has not provided any evidence of tightening pipeline tolerances. In response, AIU states that its actual position is that the operations of interstate pipelines have tightened and become more constrained, not necessarily that their stated tariff tolerance percentages have been reduced over time. AIU relates that many of the interstate pipelines that it utilizes to transport gas are operating at higher capacity levels on a year-round basis, not only due to gas-fired generation demand but also due to regional gas price differentials. AIU reports that mid-continent supplied interstate pipelines like Panhandle and Natural Gas Pipeline Company of America's Amarillo mainline system are sold out of firm capacity since they are connected to some of the least expensive gas production basins in the U.S.

AIU also relays that interstate pipelines are invoking operational restraints more frequently. According to Ameren Exhibit 30.4, there has been an increase in the frequency of interstate pipeline notices calling for specific actions to be taken by shippers on the pipeline systems due to operating constraints. This exhibit reflects a summary of interstate pipeline notifications/alerts during 2007 and January 2008 for critical and non-critical days, force majeure events, line segments being at capacity with Interruptible Transportation/Authorized Over-Run restricted, secondary out-of-path firm at scheduling risk, and line segments being out of service for maintenance.

These notifications/alerts have affected AIU's gas flows on interstate pipelines. Ameren Exhibit 30.5 contains a list of each date during 2007 that a supplier's gas failed to be delivered to the AIU city gate and the reasons why the deliveries were not made. One of the biggest supply interruption events during 2007 was the Panhandle mainline #400 rupture that occurred on November 21. As a result of the rupture, AIU reports that it experienced pro rata force majeure cuts to virtually all of the firm gas supplies being delivered by Panhandle. These cuts in gas supply ranged between 15%-20% of nominated volumes on Panhandle beginning on November 27, 2007 and lasting through January 8, 2008. During this time, AIU states that it was able to maintain the integrity of the system by utilizing its leased no-notice storage and on-system storage resources.

AIU reports that the Panhandle mainline rupture did not cause widespread cuts to the gas supply of transportation customers. In response to Data Request Ameren-CNE-2.06, AIU relates that CNE-Gas states that —between 11/26/07 and 1/8/08, CNE-Gas nominations to an Ameren LDC city gate supplied from Panhandle Eastern Pipe Line were cut due to a supplier force majeure." CNE-Gas notes, however, that —[d]uring this period, CNE-Gas made no special requests to customers to reduce usage" and that —[d]uring this period, there was no specific impact" to its customers. Similarly, in its response to Ameren's Data Request Question No. 1.04, AIU states that IIEC indicates that three of its member companies received service from Panhandle and only one had gas supplies cut off or scheduled off by the pipeline and none of the three had their supply deliveries affected at their facilities. AIU contends that these transportation customers were able to maintain normal usage levels despite the Panhandle rupture because AIU back-stopped the shortage in gas supplies for the transportation customers, similar to the six examples previously discussed (and detailed in Ameren Ex. 30.6), by utilizing system supply resources which, again, are paid for by system sales customers.

AIU states that neither Staff nor CNE-Gas has a sufficient response to its evidence of additional operational restrictions, notifications, and alerts on the interstate pipelines. AIU contends that Mr. Sackett gives no consideration to the factual evidence provided in this proceeding. Subsequently, in response to Staff data request POL 13.11, AIU provided four years of historical data for three of its largest interstate pipelines, which clearly demonstrate an increasing trend of pipeline critical notices numbering over a thousand. While Mr. Sackett acknowledges AIU's response to POL 13.11, AIU states that he then devotes only two sentences to this evidence by saying —Ameren responded to Staff DR Pol-13.11, in which it presented additional summary information that does show that some operational notices increased from 2004 through 2007. However, [Ameren witness Glaeser] offers in his DR that no more than half of these affected Ameren customers." (Staff Ex. 23.0 at 16) AIU observes that Staff fails to mention that all of these notices were critical in nature and exceeded 1,000 in number. AIU contends that this is yet another example of how Staff ignores factual evidence provided by AIU and provides absolutely no evidence of its own. Similarly, CNE-Gas states that AIU has provided —no valid evidence as to whether upstream interstate pipelines are issuing OFOs and other restrictions with increasing frequency" when questioning whether the new balancing tolerances and transportation service changes are required to protect system integrity and operations. (CNE-Gas Ex. 2.0 at 14) As with Staff, AIU asserts that CNE-Gas simply disregards the evidence provided, while at the same time providing no evidence of its own.

Staff's view that AIU has provided very limited anecdotal evidence of any gaming behavior and no quantification of any harm to sales customers is also mistaken, according to AIU. In its responses to the IIEC Data Requests 2.34, 2.35, and 2.36, which were also provided to Staff, AIU states that it provided detailed examples and in-depth discussion of six individual operating days of transportation imbalances on the system. The information encompassed three examples of transporters net shorting the system and three examples of transporters net longing the system. In each of these examples, AIU states that factual information was provided that would enable a reasonable reader to quantify the cost impact of the imbalance on the system sales customers. AIU calculates that the cost of the three long days totals $51,361 and the cost of the three short days totals $47,822, for a total impact of $99,183 for the six days. AIU contends that Staff chose to ignore the physical evidence by ignoring the value of system gas which was used to manage these imbalances. Even without doing the math, AIU states that the examples clearly show that system resources were used to handle the transporter's imbalance swing and that these system resources were being paid by AIU sales customers. AIU states further that none of the parties in this case dispute the fact that transportation imbalances (longs and shorts) occur at some level every single day on each of the systems. AIU argues that accepting Staff's recommendation means it's a certainty that system resources will be used more and more by transporters at the expense of residential and small commercial sales customers.

With regard to gaming behavior, AIU provided Staff in response to Data Request POL 6.05(g) with concrete examples of two marketers that repeatedly game the systems time and time again for economic gain, including one marketer that games between utilities from weekday to weekends. AIU maintains that some marketers are basically shifting their scheduled gas deliveries on the weekends between customer accounts that are balanced daily and those that are balanced monthly, to avoid having to decrease their gas supplies flowing to the system when the customers' usage decreases substantially on Saturday and Sunday. The marketers move the gas to the monthly balanced customers rather than decreasing the deliveries because gas supplies are typically purchased on a ratable basis over Saturday-Sunday-Monday periods. If the marketer bought the gas only for one of the three days, it would have to pay a premium for the gas or acquire balancing services on the interstate pipeline. AIU observes that one marketer is doing this on the AmerenIP system by shifting gas between Rate 76 daily balanced customer accounts and Rider OT monthly balanced customer accounts. The other marketer, AIU states, actually does this shifting maneuver from daily balanced AmerenCIPS customer accounts to AmerenCILCO monthly balanced accounts.

In response to Mr. Sackett's suggestion that by eliminating the difference between the daily price and the cashout price, any arbitrage opportunity is eliminated, AIU understands the bottom line summary of Staff's arbitrage example to be that the utility's sales customers foot the bill for the arbitrage gain achieved by the transportation customers who may be intentionally either over-delivering or under-delivering gas to the LDC system. AIU agrees that arbitrage opportunities are minimized by Mr. Sackett's suggestion of having daily cashout pricing based upon daily market prices.

ii. AIU's Banking and Balancing Proposal

AmerenCIPS and AmerenCILCO currently offer banking services in the amount of 10 times the average daily peak month ("ADPM")[11] and AmerenIP offers 12 times maximum daily contract quantity, but only for the 87 customers served under AmerenIP Rider OT. All other AmerenIP transportation customers served under Rate 76 currently have no bank service. In its original filing, AIU proposed to eliminate the banking services currently in place for AmerenCILCO and AmerenCIPS as well as the limited banking services available to AmerenIP customers under Rider OT (by eliminating Rider OT as discussed below). Upon further consideration, however, AIU now proposes banking services for all three Illinois gas utilities in the amount of 8 times the ADPM in the prior rolling 12-month period. AIU proposes to revise the banking services for two purposes: (1) bring consistency to the terms and conditions of service among all three companies through Rider T, and (2) to facilitate the continued provision of efficient service in light of emerging economic and industry challenges and trends.

The first reason for revision is self-explanatory: it is plainly beneficial for AIU and its customer to have uniform terms and conditions for transportation service common among all three utilities. As for the second reason for revision, concerning emerging economic and industry challenges and trends, AIU relates that in order to provide service to both transportation and sales customers efficiently, it is important that it anticipate operation needs across its system. Operations of transporting customers typically do not allow them to predict with exact certainty when and how much their future maximum gas demand will be. AIU states that a ―bank" is a reserve that transportation customers can tap into to avoid the undesirable financial effects of failing to keep their gas usage within defined tolerance limits. As AIU witness Glaeser explains, banks essentially allow the transportation customer to borrow gas from AIU on days that such a customer may under-schedule and end-up short on gas delivered by suppliers. Banks are used in conjunction with tolerance limits in this manner to give flexibility to transportation customers.

The reforms of its balancing tolerances is another aspect of AIU's overall effort to bring continuity to transportation service across all three companies and to update the terms and conditions of said services as modern economic and industry trends necessitate. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing with daily cashouts as well as monthly cashouts for any imbalances at the end of the month,

[11] ADPM is the average daily peak from the peak month in the past 12 months.

while AmerenCILCO has only monthly cashouts. AIU views the daily balancing tolerance provision as an important tariff provision because it helps to ensure that AIU can continue to meet the needs of both transportation and sales customers under terms and prices that are reasonable to both. Daily balancing is similar to monthly balancing, the difference being that the time unit upon which a cashout is based is a day rather than a month. AIU states that the actual percentage of daily tolerance allowed by AIU is important because the greater flexibility in balancing tolerances, the greater the isolation that transportation customers have from the economic effects of mismatching the gas they have scheduled for transportation and their actual usage.

AIU proposes to eliminate monthly balancing and cashouts and utilize daily balancing and cashouts alone for each gas utility. AIU believes that daily cashouts will negate the incentive for transportation customers to under- or over-deliver gas supply compared to customer demand. AIU proposes to change the daily imbalance tolerance range to +/- 15% of nomination for each gas utility (it had originally proposed +/- 10%). AIU states that this would effectively provide an operating window of 30% for transportation customers and an intra-month banking level of 4.5 days ((MDQ x 15% daily tolerance x 30 days)/MDQ), where MDQ represents maximum daily quantity. AIU also contends that this will more closely align with the tolerance ranges of the LDC's upstream interstate pipelines. While CNE-Gas is correct that upstream pipeline companies do not have daily cashout, AIU asserts that they do operate with daily tolerance limits ranging from 5% - 10%, and exceeding those limits can result in penalties and other charges.

Specifically, AIU explains that the cash-out proposal is such that whenever the bank limit is maximized, any excess volumes delivered each day are cashed out at 90% of the daily Chicago City Gate price. Imbalance volumes outside of the 15% tolerance band are cashed out with over-deliveries cashed out at 90% of the daily Chicago City Gate price and under-deliveries cashed out at 110% of the daily Chicago City Gate price. Mr. Glaeser adds that in the event an OFO is declared, the daily balance tolerance and bank limits operate in the same manner, with the exception that under-deliveries between 15% and 50% of the daily confirmed nomination ("DCN") are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Over-deliveries in excess of 15% continue to be cashed out at 90% of the Chicago City Gate price. He testifies that the purpose behind these provisions is to ensure an asymmetrical cash-out structure during OFO periods, in order to discourage under-deliveries during periods of constrained system operations. In the event of a Critical Day or curtailment, Mr. Glaeser states that the daily balance tolerances are reduced to zero and all imbalance volumes that deviate from the DCN are cashed out. All over-deliveries are cashed out at 90% of the Chicago City Gate price, while under-deliveries from 0% to 50% are cashed out at 150% of the Chicago City Gate price, and under-deliveries in excess of 50% are cashed out at 200% of the Chicago City Gate price. Again, he states that the purpose for this particular structure was to strongly discourage under-deliveries during Critical Days to preserve system integrity.

AIU notes that Mr. Sackett supports a bank limit of 10 times the maximum daily contract quantity (―MDCQ"), while CNE-Gas favors banking service with a limit 14-16 times the MDCQ. CNE-Gas' proposal, however, depends on the availability and flexibility of other features of Rider T. Specifically, CNE-Gas proposes to increase the banking limits to 10-12 times a transportation customers' MDQ if the daily tolerance stays at 20%. If the daily tolerance band is lowered to 15%, CNE-Gas proposes to increase the banking limits to 11.5-13.5 times a transportation customers' MDQ. If Staff's proposal for daily cashout and banking is adopted, CNE-Gas supports a banking limit of 14-16 times a transportation customers' MDCQ.

AIU notes that these proposals dramatically increase the allowable bank limits over the levels that are currently in effect for AIU. All of the bank limit proposals advanced by CNE-Gas and Staff are based on a specific number, e.g. 10, 12, 14, or 16 times a transportation customers' MDQ or MDCQ. These terms refer to the maximum daily contract quantities defined in a transportation customer's contract and are in many cases substantially higher than a customers' actual usage.

Despite the arguments of Staff and interveners, AIU proposes to allow customers a bank limit equal to 8 times the ADPM in the prior rolling 12-month period. This bank limit will allow the customer to under- or over-schedule gas and avoid cashout when operating outside of the proposed tolerance limit of +/- 15% until the limit is either exceeded or the balance is depleted. Additionally, AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. This important addition to banking services will assist in giving greater flexibility to transportation customers and mitigate the loss of flexibility associated with the necessary lower banking limits. AIU is also willing to modify the cashout mechanism to eliminate the utilization of the PGA rate and to base cashouts, both positive and negative, on the Platt's Gas Daily ―Midpoint for Chicago Citygates," which represents a market based price.

b. Staff's Position

i. Comparison of Proposals

Staff identifies five differences between Mr. Sackett's banking proposal and AIU's proposal: (1) the size of the banks, (2) the balancing tolerance, (3) the application of cashout premiums, (4) the resulting injection and withdrawal limits, and (5) access to banks on critical days. With regard to the size of the banks, Mr. Sackett proposes that the bank size be 10 times MDCQ while AIU proposes 8 times ADPM. MDCQ reflects a larger measure of the demand put on the system than ADPM and will be used by AIU in its demand charges. IIEC recommends 10 times ADPM and CNE-Gas proposes 14-16 times MDCQ, if a straight daily cashout is approved. Mr. Sackett observes that the Commission ordered Nicor to use a 28 times MDCQ limit for its banking service in Docket No. 04-0779, so he believes that including the MDCQ metric is consistent with other Commission Orders. He explains his basis for the 10 times MDCQ level as being a compromise between the 12 times MDCQ currently available to AmerenIP Rider OT customers and the 10 times ADPM currently available for Rider T banks at AmerenCILCO and AmerenCIPS.

With respect to the balancing tolerance, Mr. Sackett maintains that the 20% band currently in place does not need to be reduced to the 15% that AIU has proposed. He argues that AIU's evidence was purely anecdotal and its calculations of detriment were grossly over-stated. Under his proposal, with the straight daily cashout, the spread between market price and the cashout value is eliminated, which he believes will remove any incentive for transporters to game the system to exploit favorable economic conditions.

Mr. Sackett asserts further that AIU characterizes its proposal to reduce its daily balancing tolerance as a necessary consequence of decreasing tolerances on the pipelines from which it receives service. He notes, however, that a historical review of the tariffs for the interstate pipelines that AIU pointed to in support of an alleged trend toward the tightening of tolerances revealed that the current tariff sheets are nearly identical to tariff sheets in place in 1995-1997. Mr. Sackett avers that there have been no significant tariff revisions with regard to imbalance penalties and cashouts in the last five years that would require any changes in AIU's tariffs. In fact, he adds, some overrun charges have even declined on NGPL since 1995.

Staff states that AIU did not respond directly to Mr. Sackett‘s criticisms regarding the pipeline tolerances; instead, it sidestepped that issue and attempted to make it appear that what it really meant was that there were increasing operational issues. AIU supported the operational issues argument by alleging a trend of increased OFOs caused by operating constraints. Staff responds that the increase in OFOs demonstrated by AIU do not justify decreasing the daily balancing tolerances as proposed by AIU. Mr. Sackett asserts that no other major Illinois gas utilities – Nicor, Peoples, and North Shore – have eliminated storage services for transportation customers.

Concerning cashouts, Mr. Sackett‘s proposal would apply the cashout mechanism to the post-bank imbalance. Thus, under his proposal, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as —dumping” gas on the system. Mr. Sackett contends that AIU's proposal, which applies the cashout bandwidth to the initial imbalance before any use of the customers‘ bank, does treat withdrawals from the bank as the use of system gas and injections into the bank as —dumping” gas on the system. In addition, he notes that AIU would treat all gas left on the system in excess of the bank limit differently than the imbalances at the other end of the bank. Under AIU's proposal, Mr. Sackett understands that excess gas is automatically cashed out at 90% regardless of the percentage of the initial imbalance. If the bank balance is insufficient to cover the initial imbalance, it would be cashed out at 110% of the market only if it was in excess of the 15% band. Under his proposal, all normal imbalances are treated symmetrically.

Mr. Sackett explains further that the tolerance band should not be applied to the customer‘s initial imbalance, but rather the net customer usage of system resources after the injection or withdrawal is complete. Customer usage of system gas in excess of 20% of what is available from that customer‘s bank should be cashed out at 110% of the market price for that day. He believes that his approach removes the incentive to arbitrage price since transportation customers would have no incentive to over- or under-deliver. Mr. Sackett asserts that the addition of gas to the bank and the withdrawal of the gas from the bank do not constitute using system gas, but gas that already belongs to the transportation customer. Injecting gas is not —dumping” gas; it is using the resources approved by the tariff, according to Mr. Sackett.

Mr. Sackett testifies further that a 20% withdrawal and 20% injection limit should be in place. He asserts that this permits transportation customers to use their banks for balancing and limited physical hedging. He adds that this gives transportation customers more of the benefits that sales customers receive from storage. In general, Mr. Sackett believes that a customer should be allowed discretion in using its bank; some of the benefits from the bank are from balancing and some from storage.

If the Commission determines that standardizing the tariffs to provide for a daily cashout is appropriate, Staff argues that it should approve tariff provisions that modify the AmerenCIPS tariff design to eliminate the proposal for monthly balancing. Staff states that the current AmerenCIPS tariff has daily balancing along with a bank and offers the option of a stand-by reserve ("SBR"). This design allows for the most options for transportation customers while closing up some of the —flaws” AIU alleges are in the existing tariff.

Staff also reports that when AIU proposed its bank limit service, it included no access to the bank on a Critical Day despite the fact that all of its current banks allow for limited access. Mr. Sackett believes that the tariff should allow limited access to the bank on a Critical Day with wording similar to AmerenCIPS‘ existing method, if the Commission approves the retention or expansion of the SBR (total use of system gas and bank withdrawal equal to the designated SBR amount). If the Commission does not approve the retention or expansion of the SBR, Mr. Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks (50% of MDCQ).

ii. Access to Storage Assets

A central difference in the case has been Mr. Sackett‘s objection to the reduced access to storage assets. AIU maintains that those resources are solely required to meet the needs of its sales customers. Mr. Sackett disagrees with this for six reasons.

First, Mr. Sackett objects to AIU not providing equal access to storage resources for transportation customers by linking use of its monopoly storage resources to the purchase of a commodity. He explains that because system customers receive the benefit of the on-system storage through lower costs, if AIU eliminates or reduces the bank for transportation customers, when a customer switches from sales to transportation service, the switch results in the customer being denied the use of utility storage assets.

Second, Mr. Sackett notes that the Commission has consistently taken the position that system assets are for the benefit of all customers. When a customer shifts from system supply to transportation service, Mr. Sackett contends that access to system assets should be retained. He asserts that transportation customers, through their fees, compensate the utility for the appropriate use of utility resources that exist to serve all customers. Mr. Sackett rejects the premise that these assets should be used to meet the needs of sales customers first and foremost.

Third, CNE-Gas argues that while ―Ameren claims it does not have the resources necessary to provide storage service to transportation customers, [t]he real question of equity is not whether there is enough storage available, but how to fairly allocate the storage that is available . . . . It is inappropriate to simply conclude that because a utility has fewer total volumetric amounts of storage resources than another utility that it should not have to equitably allocate the resources it does have." (CNE-Gas Ex. 1.0 at 16-17) Both CNE-Gas and Staff point out that the ratio of owned storage assets to throughput shows that AIU has sufficient assets to share them with both customer groups. AIU objects to only looking at owned storage but Mr. Sackett notes that AIU itself made a distinction between the two when it claimed that it needed all of its owned storage assets to meet peak day demand for its sales customers and most transportation customers pay for the use of on-system storage.

Fourth, AIU also makes the argument that transportation customers can purchase these same basic services on the interstate pipelines. Mr. Sackett contends, however, that the services offered by the interstate pipelines are not a reasonable substitute for the services provided by the LDC. He argues that these services are not close substitutes to LDC services for several reasons, including the restrictive nature of AIU's tariffs. Mr. Sackett states that interstate pipeline balancing service addresses only the problem of an imbalance with the pipeline; it would not address imbalances with the LDC. Differences between deliveries from the pipeline to the LDC and the customer's usage must be addressed by a balancing service provided by the LDC itself, according to Staff.

Fifth, AIU argues that it requires all of its owned storage resources to meet peak day demand for its sales customers and that the Commission has approved this allocation in PGA proceedings. Staff asserts that Commission findings of prudence in a PGA proceeding do not demonstrate an understanding and acknowledgement that the resource allocation of AIU's peak design day excludes transportation customers. The PGA proceedings deal with cost recovery and do not include a thorough review of the allocation of storage assets between sales and transportation assets. Mr. Sackett adds that it is not clear from the demand studies that AIU has provided whether or not AIU includes transportation customers in its peak design day. AIU's witness testifies that he believed that banks' withdrawals and imbalances were a part of the ―historical look" provided by this demand study. AIU's witness also agrees that customers have a right to withdraw gas from their banks on a Critical Day until undergoing curtailment. However, since curtailment does not affect all transportation customers or transportation customers exclusively, Staff contends that AIU must be meeting some of this demand even during a curtailment. Staff asserts that Mr. Glaeser‘s artificial (and confusing) distinctions about exactly where this gas comes from should carry no weight with the Commission because there is no difference between the gas that flows from the storage fields and that which is flowing from line pack or other system resources.

Sixth, AIU claims it is not providing ―storage" for transportation customers, although it admits it is providing banking services for transportation customers under both AmerenCILCO's and AmerenCIPS‘ current Rider T and AmerenIP‘s Rider OT. Staff states that this is a distinction without a difference. Staff explains that banking is a service whereby a transportation customer delivers more gas than it consumes. This gas, under specified circumstances, is taken by the utility and the transportation customer has specified rights to have that amount of gas returned to the transporter when its usage exceeds its deliveries from the pipeline to the utility system. Staff contends that storage fields provide flexibility to address differences between deliveries into the utility system and usage by its customers (sales and transportation). While the companies may account for transportation customers‘ banks as a general obligation to provide a similar amount of gas back to them, storage fields certainly facilitate this practice. Indeed, to support a reduction in transportation customers‘ access to storage services, Staff relates that AIU misleadingly argues that it lacks the excess storage capacity that other utilities have. According to Staff, AIU offers no proof that it can not provide Staff‘s recommended storage services.

iii. Gaming

Staff observes that AIU has also listed potential gaming as a major factor for many of its tariff changes. Mr. Sackett points out three reasons why AIU's argument has no merit: (1) reliance on anecdotal evidence, (2) flawed calculations of detriment to sales customers, and finally, (3) the presence of other, more focused options to address gaming if it did exist. First, Staff asserts that the anecdotal examples AIU provided fail to demonstrate gaming. Similarly, Mr. Sackett testifies that AIU failed to consider net effects of imbalances in the opposite direction. Before tariff revisions should be made to address gaming, Staff states that AIU must demonstrate that gaming exists. Staff contends that AIU has proposed dramatic changes to address a problem that it has failed to demonstrate exists.

Second, Mr. Sackett pointed out flaws in AIU's analysis of the detriment and cost to other customers. When calculating the negative impact on sales customers, he observes that AIU neglected to account for its cashout rules. Mr. Sackett contends that this omission causes a gross overestimate of the cost that the imbalances impose on sales customers. Staff submits the cashout rules protect sales customers, and as a result of the cashout rules, Mr. Sackett indicates that these imbalances might end up benefitting sales customers.

Specifically, in its analysis of over-deliveries, Staff maintains that AIU miscalculates the detriment to sales customer by using the avoided cost of the transportation customers. Staff contends that AIU fails to acknowledge that transportation customers have suffered a loss in the value of the gas that they bought at the First of the Month price regardless of whether they sell the gas at a loss that day or store the gas on AIU's system. Staff asserts that AIU incorrectly suggests that the customers avoid this loss by putting gas onto AIU's system and uses this spread multiplied by the net positive imbalance to calculate the cost to sales customers. Staff argues that it is unreasonable to calculate the dollar amount of cost to the system sales customers and to include the value of the supposed benefit to transportation customers as a cost to sales customers.

In analyzing under-deliveries to the system, Mr. Sackett testifies that AIU fails to account for the different methods by which the negative imbalances are cashed out. Some negative imbalances are cashed out at the market price plus 10%, some get ‗repaid' by positive imbalances during the remainder of the month, and the rest get cashed out at the end of the month. Mr. Sackett argues that AIU's calculation, which multiplies each imbalance by the full spread between the daily price and the end of month price, overstates the size of the detriment to sales customers because it ignores those other cashouts.

Third, Mr. Sackett asserts that his recommended tariff modifications are more focused and thus would better resolve the problem. He suggests that AIU's daily imbalances could be cashed out at the daily spot price. He believes that this proposal addresses the possibility of an arbitrage occurring because of a difference between the cashout price (the average of the daily prices for the month) and the market price for a particular day. Mr. Sackett states that the incentive for arbitrage could arise if the daily price were high relative to the expected average monthly price; a customer might have an incentive to arbitrage the two prices by under-delivering gas on that day. Alternatively, if the daily price is low compared to the expected average monthly price, a customer might have an incentive to arbitrage the two prices by over-delivering gas on that day. Mr. Sackett contends that his recommendation would eliminate the difference between the daily price and the cashout price, thus eliminating the arbitrage opportunity. He adds that premiums on the cashout price for imbalances greater than 20% bands would be employed to encourage accurate nominations. Customers using system gas in excess of that 20% would be cashed out at 110% of the market price for that day. Over-deliveries would roll into a bank to the extent there it is not full up to 20 percent of the excess delivery; any additional gas would be cashed out at 90% of the daily price. Finally, the order of deliveries would follow the Commission-approved tariff in AmerenCIPS' Rider T.

Staff opposes the "extra" penalties for over-deliveries during OFOs and Critical Days. Staff recommends that over-deliveries on such days be cashed out exactly the same as other deliveries. Staff contends that over-deliveries by transportation customers will help the utility meet its supply shortcomings for sales customers on such occasions.

c. IIEC's Position

IIEC is opposed to the elimination of the current banking provisions for AmerenCILCO and AmerenCIPS and recommends the 10-day of MDQ banking allowance be applied to all three of the AIU utilities. The fact that AIU is agreeable to providing storage equal to 8 days of ADPM demonstrates, in IIEC's opinion, that AIU does not need all of its storage to serve its sales customers. IIEC contends that AIU should provide storage banks equal to 10 days of MDQ to all of its transportation customers as a matter of equity and to facilitate the broader use of its system.

IIEC notes that AIU proposed to restrict customers' ability to use even the 8-day bank. Under AIU's latest proposal, IIEC understands that customers would be required to cashout any imbalances in excess of AIU's proposed 15% tolerance limits even if the customer had sufficient gas in its bank to cover the full imbalance. Specifically, under AIU's proposal, if a customer under-delivers to the system, but has sufficient bank balances to cover that under-delivery, the customer will only be allowed to withdraw an amount of gas from his bank that is less than or equal to the 15% daily tolerance amount. If the customer has a shortfall in deliveries of 17%, the extra 2% must be cashed out. IIEC argues that AIU has not shown that imbalances cured by the use of the customer's own banked gas will have any adverse impact on the amount of costs AIU incurs to serve its sales customers. IIEC maintains that transportation customers should be allowed to cure any imbalances by adding to or withdrawing from gas in their banks whether within the tolerance limits or not. In other words, if the customer's gas supply is unavailable on a particular day, but the customer has sufficient gas in its storage bank to cover its usage, it should be able to use that banked gas to meet its needs without having to cash out usage in excess of the daily 15% tolerance.

With regard to the specific tolerance limit proposed by AIU (15%), IIEC maintains that AIU has not shown any need to tighten the tolerances currently in place for AmerenCIPS and AmerenIP. IIEC recommends maintaining the present 20% tolerance limit and the application thereof to all three companies. IIEC contends that the only evidence of any problems provided by AIU relate to its examples using six "hand picked" days when there were large imbalances on the system. In its calculations, which purport to calculate the harm to sales customers as a result of transportation customers' actions on these days, IIEC states that AIU apparently did not reflect offsetting imbalance charge payments from transportation customers in its analysis. Thus, IIEC concludes, AIU's analysis is incomplete and fails to consider that sales customers may have benefitted from the events described.

In addition, IIEC reports that AIU has incurred only minimal imbalance penalties under the current 20% tolerances for AmerenCIPS and AmerenIP, thus it is not clear what problem AIU is addressing in reducing the tolerances from 20% to 15%. IIEC contends that AIU has not provided sufficient evidence of harm to sales customers as a result of the actions of transportation customers under its existing tariffs, so as to justify a reduction in the daily imbalance tolerances. IIEC states further that AIU (1) has not provided specific studies or investigations, (2) has not provided sufficient proof or evidence that the gaming behavior alleged in its testimony has actually occurred, and (3) has not demonstrated that the behavior of transportation customers has systematically or consistently raised costs to sales customers. Absent a clear demonstration that there is a problem with the current 20% tolerances, IIEC asserts that they should be maintained, and applied to all the companies, but only as long as a bank equal to 10 times the customer's MDQ is made available.

d. CNE-Gas' Position

CNE-Gas understands AIU to be proposing a bank limit for each gas utility based upon 8 times the ADPM. CNE-Gas also understands that the ADPM is the same methodology that is currently employed by AmerenCILCO and AmerenCIPS in determining bank size except that the number of days used is currently 10 versus the 8 proposed. CNE-Gas observes that not only is 8 days less than the current 10-day banking service, but also the use of ADPM results in less bank capacity than if based upon an MDQ or MDCQ as is used by AmerenIP and other Illinois gas utilities. CNE-Gas states that there is no quantifiable data to support 8 days per se; it is simply offered as a compromise. While some banking is better than none, CNE-Gas continues to have concerns with: (1) the size of the bank, (2) the ability to inject and withdraw gas from that bank, (3) the parameters for bank limit transfers, or imbalance trades, and (4) the 15% daily tolerance limit.

i. Access to Storage

CNE-Gas asserts that it and AIU have markedly different views regarding AIU's storage assets. CNE-Gas understands AIU's position to be that company-owned storage assets are exclusively for the benefit of sales customers and that its resources are insufficient to provide equivalent storage service to transportation customers. According to CNE-Gas, AIU posits that transportation customers should at best benefit from its storage assets only to the extent storage is needed to provide a minimum level of balancing. AIU seeks in these proceedings to reduce the balancing flexibility afforded to transportation customers. CNE-Gas, however, contends that AIU has offered no studies or formal analysis to warrant this reduction.

When AIU's storage fields were developed, virtually all of its customers were bundled sales customers. Today, CNE-Gas notes that AIU's customers have a choice of gas supplier, and the Commission has taken steps in the recent Nicor and Peoples rate case orders to ensure that customers electing to purchase gas on an unbundled basis from suppliers other than the LDC are able to obtain transportation services that include equivalent use of the utility's resources, including storage. CNE-Gas reports that the Commission previously determined that Nicor's current allocation process for firm storage that is based upon MDCQ is fair to all customers. CNE-Gas relates that Nicor determines allocations by dividing the total amount of storage by the peak day sendout, with the result constituting the firm storage or SBR entitlement, authorized at 28 times MDCQ, for each customer including sales customers, customer select customers, and transportation customers. CNE-Gas argues that AIU can not reserve storage for sales customers alone, as AIU's storage assets are utility customer assets rather than sales or transportation customer assets. CNE-Gas states that a full share of AIU's storage assets must be made available to each firm customer class under equivalent terms and conditions of service.

CNE-Gas states further that other Illinois gas utilities provide storage not only for balancing purposes, but also storage that allows transportation customers to purchase less expensive summer gas for consumption during the winter when prices are generally higher. CNE-Gas contends that AIU faces the same environment of price volatility and constrained energy infrastructure that other Illinois gas utilities face, yet other utilities have not found it necessary to reduce transportation customer storage banks to the minimal levels proposed by AIU. Moreover, CNE-Gas continues, AIU's proposed denial of comparable storage is not only unduly discriminatory, but also would result in an unfair competitive advantage for bundled utility sales service over third party suppliers. CNE-Gas asserts that AIU's undue discrimination is illustrated by the outcome that if an AIU transportation customer elects to return to sales service, that customer would again have access to AIU storage through bundled sales. The storage assets are available to support all customers. CNE-Gas states that AIU simply elects to deny storage rights to customers that deign to purchase gas from its competitors. Ultimately, CNE-Gas fears that permitting AIU to preserve such a competitive advantage for its bundled sales service will stifle competition and reduce customer alternatives.

ii. Sufficiency of Storage Resources

CNE-Gas suggests, in evaluating AIU's argument -- that there are insufficient resources to provide larger storage banks to transportation customers -- the Commission should not ask whether there is enough storage available but how to allocate fairly the storage that is available. Even though storage resources may be limited, CNE-Gas contends that it is equitable that all utility customers share equally in those assets that do exist. CNE-Gas and Staff offered evidence comparing AIU's storage assets with those of other major Illinois utilities. Although AIU argues it has inadequate storage resources to offer more than 8-day bank limit service, CNE-Gas argues that comparisons with other Illinois utilities dispute such a claim. While differences exist between utility assets that warrant differences in the services offered by each utility, CNE-Gas maintains that the small differences in storage assets do not warrant the substantial differences between service offerings that AIU proposes compared to Peoples, North Shore, and Nicor.

On page 16 of its Initial Brief, CNE-Gas provides a table summarizing the storage assets of six Illinois gas utilities, including the three AIU LDCs. Based on total storage as a percentage of annual customer use, CNE-Gas observes that AIU has somewhat less storage available than either Peoples or Nicor. This slightly lower capacity, however, does not justify transportation storage banks that are less than one-third of the capacity of the storage banks offered by the other utilities, according to CNE-Gas.

CNE-Gas reports that in 2006 AmerenIP, the largest of the three AIU gas utilities had annual transportation throughput of 33.5%. CNE-Gas states that in contrast, Nicor in its last rate case reported transportation gas throughput of 47.1%, and, Peoples in its recent rate case reported a volume of just over 40%. CNE-Gas contends that AIU's successful transition to unbundled competitive alternatives will not match the success of Nicor or Peoples if the Commission permits it to skew the benefits of storage access towards its bundled sales customers.

CNE-Gas urges the Commission to authorize transportation storage banks of 12 times MDCQ if daily balancing tolerance remains at 20%. If the daily balancing tolerance is reduced to 15%, CNE-Gas states that a storage bank of 13.5 times MDCQ is more reasonable. In either case, CNE-Gas notes that the AIU storage bank would still remain comparatively lower than those of other Illinois utilities.

CNE-Gas claims further that it is unnecessary to establish extreme safeguards for sales customers that are designed to remedy purely hypothetical ills, especially when they result in the allocation of excessive costs to transportation customers. CNE-Gas does not believe that AIU provided adequate evidence that a reduction in the size of transportation customer storage banks is warranted. In support of its position, CNE-Gas asserts that (1) AIU's anecdotal examples of gaming of the system or subsidization of transportation customers were discredited, (2) AIU did not establish that reduction in the size of storage banks is essential to project system integrity, (3) AIU's storage banks for transportation customers are already relatively smaller than those of other Illinois utilities, (4) storage assets are utility assets that should be equitably allocated between both sales and transportation customers, and (5) imbalances are normal operating conditions for which storage banks are a reasonable and proven means to address.

Regardless of the Commission‘s decision regarding storage allocation, CNE-Gas recommends that AIU be required to investigate the storage allocation methodologies of both Peoples and Nicor. The Commission, CNE-Gas continues, should order AIU to work with Staff and interested stakeholders to study the impact of utilizing these other storage allocation methodologies in order to more equitably allocate storage assets between sales and transportation customers in the future.

iii. Injection and Withdrawal Requirements

CNE-Gas states that the function of a storage bank depends not only upon the total volume of the bank, but also the ability to inject gas into the bank and withdraw gas from that bank. Unfortunately, CNE-Gas finds that AIU's proposed bank limit service makes it extremely difficult to inject or withdraw gas from storage on a planned basis when the supplier is concerned that the amount in the bank is too low or high. The design of the service allows storage injections or withdrawals only to extent that the quantity of gas remaining is within 15% of the DCN after any imbalance between actual usage and deliveries is taken into account. As an example, CNE-Gas states that ―fia supplier anticipates a customer will use 850 therms/day, but also wants to inject gas into its storage banks, if the customer has sufficient capacity in its bank, the supplier may make a nomination of 1,000 therms, hoping that 150 therms will be injected into its bank." (CNE-Gas Initial Brief at 18) Since an imbalance invariably occurs if the customer has a 6% imbalance and actually uses 800 therms for the day, with the DCN of 1,000 therms, 150 therms would be injected into the storage bank, and the remainder would be purchased by AIU at a discount of 90% of the market price. To avoid this penalty, CNE-Gas states that the supplier's only recourse is to lower the DNC, thereby reducing the risk of selling gas to AIU at the discount, but also lowering the quantity of gas injected into storage. Id.

If the 6% imbalance occurred in the opposite direction, and the customer instead uses 900 therms rather than the 850 anticipated, with the DCN of 1,000 therms, only 100 therms are now available for injection. Since usage projections are not precise, and any unanticipated imbalances must first be accounted for, CNE-Gas contends that storage injections are haphazard at best under AIU's proposal. Over weekends and holidays, when the ability to forecast usage is even more challenging, CNE-Gas fears that actual imbalances may deviate more than even the 15% daily balancing tolerance, resulting in a storage withdrawal when an injection was planned or vice versa.

In the above examples, the customer either made a storage injection of 9% of the DCN or, when making a storage injection of 15%, also was forced to sell any excess gas at a discount. At best, the customer could make an injection of up to 15% of DCN without a penalty. The latter scenario, CNE-Gas states, assumes perfect knowledge of customer usage, which is unrealistic and would seldom, if ever, occur.

In comparison, CNE-Gas points out that Nicor permits storage injections of 200% of the MDCQ compared to AIU's proposed 15% of DCN (by definition MDCQ/MDQ is larger than DCN). Even in Peoples' recent rate case, in which additional storage injection limits were implemented, CNE-Gas reports that injections of 100% MDQ during the winter months are allowed, with somewhat tighter limits during April through October. Yet, even the more restrictive injection season limits, CNE-Gas asserts, are significantly more liberal than those of AIU. CNE-Gas states that during the injection season Peoples permits injections that equate to average daily use in the parallel month of the prior year plus 0.67% of the customers' bank.

CNE-Gas urges the Commission to reject AIU's overly restrictive injection and withdrawal limits. CNE-Gas notes that the Commission has previously stated that "[t]o the extent possible, the Commission would prefer to increase rather than reduce the flexibility of customers, whether Transportation customers or [other] customers." (Docket No. 04-0779, Order at 131) Because AIU's proposal is based on DCN, CNE-Gas asserts that it is more limited than Peoples' or Nicor's bank system. CNE-Gas adds that AIU would further limit transportation customer flexibility by permitting storage injections and withdrawals of only 15% of the DCN before a discounted cashout sale to AIU or premium cashout purchase by AIU.

CNE-Gas recommends that the Commission require AIU to adopt injection and withdrawal limits of one times MDQ. CNE-Gas acknowledges that even this limit is more restrictive than those of Nicor and Peoples. In the alternative, if the Commission determines limits of one times MDQ are not reasonable in this case, when storage banks have sufficient capacity, CNE-Gas believes that AIU should permit storage injections up to 100% of the DCN and, once the bank is full, excess gas would be purchased by the utility at 90% of the market index price. Since, according to AIU, its storage bank capacity is limited to no more than a handful of days, CNE-Gas states that customers would be prevented from making large, ongoing injections as their storage bank capacity would max out rather quickly. Thus, customer deliveries to storage are limited to less than 15% or 20% (depending upon the daily tolerance level approved) on most days. Storage withdrawals, CNE-Gas adds, would be limited to actual daily usage; however, once the storage account has a zero balance, any purchase of gas from AIU for balancing purposes would be made at 110% of the market index price.

iv. Imbalance Tolerance

While CNE-Gas prefers AIU's current 15% daily tolerance proposal over its original 10% proposal, CNE-Gas asserts that there are several reasons that it is more appropriate for AIU to use a 20% daily cashout imbalance parameter. First, CNE-Gas states that a daily cashout already introduces a significantly new concept for AmerenCILCO customers, which currently only use a monthly cashout. Second, because AIU proposes to continue to use a monthly cashout in conjunction with a daily cashout, CNE-Gas contends that even at a 20% daily tolerance, AIU continues to capture monthly imbalance deviations through its graduated tier of premiums and discounts.

Third, CNE-Gas questions AIU's argument that it needs to reduce its daily tolerance to 15% in order to align more closely with the tolerance ranges of the LDC‘s upstream interstate pipelines. CNE-Gas points out that none of the pipeline tariffs under which AIU currently secures firm service has any daily cashout provision whatsoever. Under existing pipeline agreements, CNE-Gas states, AIU does not currently adhere to daily cashout of imbalances that are greater than 20%, let alone the lower tolerance level proposed. Thus, CNE-Gas concludes, there is nothing that makes AIU's proposed 15% daily cashout tolerance inherently comparable with the existing pipeline tariffs to which AIU is subject.

Fourth, CNE-Gas asserts that AIU offers no credible evidence that the current 20% daily cashout tolerance level is not adequate. AIU instead identifies existing pipeline tariff restrictions of 5% or 10% as justification for the reduction in its daily tolerance; however, CNE-Gas demonstrates that these restrictions are not directly comparable to a daily cashout tolerance as suggested by AIU. Thus, CNE-Gas argues that there is no record evidence that the current daily cashout tolerances do not offer sufficient incentive to keep transportation imbalances at reasonable levels. The situation is exacerbated, CNE-Gas continues, by AIU's proposal to retain a monthly cashout with tighter month-end tolerance levels. In response to AIU's claims of transportation customer gaming, CNE-Gas responds that AIU's anecdotal evidence does not establish that any gaming behavior has occurred.

CNE-Gas maintains that keeping imbalances within 20% on a daily basis, and less than 10% at a monthly level, before penalties are applied, is reasonable. CNE-Gas states that AIU offers no evidence that shows that the existing 20% daily cashout tolerance must be reduced to 15% in order to (1) more closely align with upstream pipelines, (2) provide additional incentive to transportation customers to reduce imbalances than what already exist, (3) address more frequent OFOs, or (4) prevent transportation customer gaming. CNE-Gas believes that the addition of a 20% daily cashout tolerance to AmerenCILCO tariffs, in addition to the retention of a 20% daily cashout in AmerenIP and AmerenCIPS tariffs, adequately resolves certain of the problems identified by AIU. CNE-Gas asserts that it is unnecessary to also add further restrictions by lowering the percentage.

CNE-Gas is also uncertain whether AIU intends to require both daily and monthly cashouts for transportation customers. CNE-Gas supports the use of a monthly cashout in addition to a daily cashout. CNE-Gas observes that under Staff's proposed 10-day storage bank, a daily cashout alone offers less storage capacity than a dual daily and monthly cashout mechanism. CNE-Gas explains that this is due to the loss of monthly cashout and the flexibility it provides to transportation customers which allows them to accumulate volumes during the course of a month. This functionality is described by AIU witness Glaeser as the intra-month bank. To remain on par with current service levels (which Staff argues should occur under an across-the-board rate increase), CNE-Gas states that under the daily cashout proposal, the size of the storage banks must be greater than the proposed 10 times the MDCQ if service levels are to remain roughly equal. While it prefers the current monthly and daily cashout mechanism in conjunction with a storage bank, CNE-Gas adds that daily cashout alone would be an acceptable alternative if less restrictive injection and withdrawal limits are implemented and the size of the storage bank is increased to account for the elimination of monthly cashout balances.

AIU further describes what happens with daily cashout and bank limits during an OFO and Critical Day. CNE-Gas states that in both instances AIU proposes extreme measures, but since these measures first appeared in surrebuttal testimony and no detailed tariff sheets were offered in support, CNE-Gas laments that interveners had little opportunity to respond. CNE-Gas contends that AIU has provided no evidence to justify why zero Critical Day tolerance is acceptable, nor why it is reasonable to discount excess gas supply under such conditions while doubling the cashout price of purchases. On a Critical Day, CNE-Gas asserts that a primary concern is having sufficient supplies delivered on AIU's system, yet if a marketer over delivers gas, AIU wants to penalize the over deliveries as well by cashing them out at 90% of market. To avoid the substantial penalties associated with under deliveries on Critical Days, CNE-Gas states that a prudent marketer may attempt to over deliver to some degree in order to avoid the under delivery penalties, yet AIU proposes to also penalize marketers for over delivery, even though on a Critical Day adequate gas supply is critical for system integrity. CNE-Gas argues that penalties for over delivery during an OFO or Critical Day simply fail any logic.

CNE-Gas reports further that AIU proposes to also implement a $6.00/therm charge for unauthorized gas usage during Critical Days. CNE-Gas states that this is in addition to the premiums just discussed that are applied to cashout. CNE-Gas does not object to implementation of the unauthorized gas charge penalty per se, but does object to the cumulative unfavorable treatment of transportation customers during OFOs and on Critical Days.

e. Commission Conclusion

As noted above, AmerenCILCO and AmerenCIPS transportation customers may currently avail themselves of a 10-day ADPM bank, and AmerenIP Rider OT customers may avail themselves of a 12-day MDCQ bank. AIU proposes to apply an 8-day ADPM bank to all transportation customers of all three utilities. Staff proposes a bank size based on 10 days of MDCQ, while IIEC proposes a bank size based on 10 days of MDQ. CNE-Gas proposes varying bank sizes depending on other factors such as imbalance tolerances.

The Commission agrees that banking service is appropriate for transportation customers. The Commission also recognizes that a reasonable size for a bank is related to other issues affecting utilities and transportation customers. Therefore, the Commission will take such issues into account when establishing a bank size for the three AIU gas operations.

One factor to consider is the ease with which banking service can be implemented. Obviously, a uniform bank size among all three utilities facilitates implementation. What also facilitates implementation and use is measuring a bank size in units already in use. As discussed above, Nicor currently calculates bank size using MDCQ, as does AmerenIP under Rider OT.[12] The fact that a customer's MDCQ will generally be known well in advance facilitates banking as well. Overall, the Commission finds that measuring a bank size through a customer's MDCQ to be reasonable and consistent with prior decisions. The ADPM unit, however, has not been applied as broadly in Illinois. Moreover, under AIU's proposal of a rolling 12-month period, the ADPM would seem to change from month to month, which the Commission believes may unnecessarily hamper and/or complicate banking.

With regard to the size of the bank, the proposals vary. AIU primarily argues that resources are simply not available to offer "large" banks. AIU also expresses concerns about gaming by transportation customers. While gaming probably occurs to some extent, the Commission is not convinced by AIU's evidence that gaming is as widespread of a problem as AIU suggests, and therefore the potential for gaming need

[12] Peoples and North Shore's tariffs indicate that they calculate bank size using MDQ, which is more similar to MDCQ than ADPM.

not be considered in setting bank size and related issues. The Commission accepts, however, that AIU has less capacity for banking than Nicor, Peoples, and North Shore. In light of the conclusions below, the Commission finds that a 10-day MDCQ bank is an appropriate size. The Commission also wishes to clarify that banks do not represent gas "borrowed" from a utility, as AIU suggests. Gas in a figurative bank represents gas owned by a transportation customer.

As for access to bank gas, if the Commission does not approve the retention or expansion of the SBR service, Staff witness Sackett believes that the Commission should order AIU to adopt AmerenCILCO's method for allowing access to banks. AmerenCILCO's current Rider T addresses access to banks and provides in part that a transportation customer on Rate 550 or 600 may access up to 50% of its MDQ while a customer on Rate 650 or 700 may access up to 50% of its MDCQ on a Critical Day. The Commission finds AmerenCILCO's current access terms acceptable with the modification that a transportation customer otherwise eligible for service under GDS-2 or GDS-3 may access up to 50% of its MDCQ on a Critical Day and one times MDCQ on normal days. For all other transportation customers, the limits for both Critical Days and normal days shall be 20% of DCN.

The appropriate daily balancing tolerance is the next issue to be resolved. AmerenCIPS and AmerenIP currently offer +/- 20% daily balancing. AIU has proposed a 15% tolerance, while Staff, IIEC, and CNE-Gas propose 20%. As noted above, the Commission recognizes AIU's resource concerns, but is not convinced that adoption of AIU's position is warranted. In consideration of the 10-day MDCQ bank size, the Commission believes that it is reasonable to adopt a 20% tolerance band. After gaining some experience with this tolerance band in conjunction with the other conclusions regarding transportation service, the Commission may revisit this issue and further revise the tolerance band (either up or down) in AIU's next gas rate cases.

With respect to cashouts following imbalances outside of the tolerance band, AmerenCIPS and AmerenIP currently employ daily cashouts as well as monthly cashouts for any imbalances at the end of the month, while AmerenCILCO has only monthly cashouts. CNE-Gas appears to want to retain both daily and monthly cashouts. AIU, Staff, and IIEC, on the other hand, recommend only daily cashouts for transportation customers. In light of concerns over whether daily telemetry is warranted for smaller transportation customers, as discussed below, the Commission is not inclined to approve daily cashouts for transportation customers that would otherwise be GDS-2 or GDS-3 sales customers. Monthly cashouts only shall be used for such smaller transportation customers. For the remaining transportation customers, daily cashouts are reasonable and approved.

The cashout mechanism should only be applied to the post-bank imbalance. In other words, when calculating an imbalance, withdrawals from the bank will not be treated as the use of system gas nor will injections into the bank be treated as ―dumping” gas on the system. Additionally, over-deliveries on Critical Days shall also be cashed out the same as over-deliveries on any other day. Over-deliveries by transportation customers will help the utility meet its supply shortcomings for sales customers on Critical Days. The Commission also notes that AIU is agreeable to allowing transportation customers that are served by the same interstate pipeline to transfer bank limit balances provided confirmation of the exchange is established. The Commission finds AIU's proposal reasonable and adopts it. AIU's proposal to implement a $6.00/therm charge for unauthorized gas usage during Critical Days is also hereby approved. If a transportation customer's gas usage is not measured by the LDC on a daily basis, for purposes of applying any penalties connected to unauthorized use on a Critical Day, the transportation customer's daily usage should be determined by prorating the total usage during the billing period over the number of days in the billing period.

2. AmerenIP Rate 76 as a Stand-Alone Tariff

a. AIU's Position

AIU witness Warwick proposes to eliminate the existing Rate 76--Transportation of Customer-Owned Gas from AmerenIP's rate schedules as part of its effort to create a new, consistent Rider T that will implement uniform terms and conditions for transportation service across all three gas distribution company service territories. The conversion would be accomplished by increasing each of the Rate 76 components by the overall base rate percentage increase and then re-segmenting the components into the non-residential GDS rates to conform to the uniform structure common to the AmerenCILCO and AmerenCIPS tariffs. AIU believes that eliminating Rate 76 in favor of Rider T will result in a tariff layout that is easier to understand and more logically consistent, which is particularly important for those entities that have multiple facilities and/or customers in the various AIU service territories.

AIU's proposal to remove AmerenIP's Rate 76 as a stand alone tariff does not affect the proposed base service rates (i.e., Customer Charge, Demand Charge, Overrun Demand Charge) of the customers affected by this change due to the across-the-board increase proposal of AIU. AIU contends that the resulting rate values are the same whether Rate 76 is a stand alone tariff or as stated under the proposed Rider T. AIU also notes that, under its proposal, changes to Rider T's service terms and conditions are applicable to current AmerenIP Rate 76 customers under either the stand alone or merged basis.

Staff witness Sackett criticizes generally the effort to consolidate transportation rate structures into Rider T and therefore opposes the elimination of the individual company transportation riders. Staff witness Harden objects to eliminating Rate 76 out of concern that doing so may result in unequal bill impacts on customers. AIU asserts that Staff supports consistency, but only if it does not create any cost impacts for transportation customers. With the across-the-board increase to each delivery service rate component, AIU states that it is not clear or apparent what, if any, unequal bill impacts may result. AIU asserts that there is no apparent record evidence to justify Staff's position.

b. Staff's Position

Because she fears that the elimination of Rate 76 could result in unequal bill impacts, Ms. Harden opposes this change and proposes that an across-the-board increase should be applied to each rate for each customer class without making any tariff eliminations that may cause unequal bill impacts. Staff also does not believe it will be clear to customers that the resulting rate values will be the same whether Rate 76 is on a stand-alone or merged basis. In addition, Staff does not agree with AIU's contention that ―in conforming tariff structures that differ across three service territories, certain provisions enjoyed by certain customers will be eliminated." (AIU Initial Brief at 330) Staff contends that AIU's choice to eliminate services and offer fewer choices to transportation customers is a deliberate one, not forced by any changing energy market requirements.

c. Commission Conclusion

The Commission does not share Staff's concerns about eliminating AmerenIP's Rate 76 as a stand alone tariff in light of the manner in which AIU proposes to do so. Specifically, it is unclear how unequal bill impacts to AmerenIP transportation customers will occur. The Commission also recognizes that AIU is not proposing to incorporate Rate 76 into Rider T as a result of changing energy markets, but rather is doing so based on its own preference. Such a motivation, however, does not alone warrant rejecting AIU's proposal. In any event, the Commission finds that its other conclusions regarding rate design will sufficiently protect transportation customers. Those who believe that additional provisions regarding transportation customers are warranted are free to raise them in AIU's next gas rate case. Intervening transportation customers and marketers have not objected to AIU's proposal.

3. Elimination of AmerenIP's Rider OT

a. AIU 's Position

AIU proposes to eliminate Rider OT--Optional Transportation of Customer-Owned Gas from AmerenIP's tariff books. AIU indicates that this rider allows customers essentially to switch back and forth between system sales gas and transportation service. AIU states that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. In response to criticism from Staff witness Sackett and GFA witness Adkisson related to rate impacts from eliminating Rider OT, AIU has proposed to grandfather existing Rider OT customers within existing GDS rate classifications. The grandfathering proposal applies to the monthly rate values only; all other terms and conditions will be pursuant to the proposed Rider T provisions. AIU explains that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. The limitation grants existing Rider OT customers AIU's recommended across-the-board percentage change and, at the same time, provides a transition mechanism consistent with Mr. Glaeser's testimony to eliminate Rider OT. AIU states that the retained Rider OT rate structures will be located within each non-residential GDS classification, GDS-2 through GDS-6. If a grandfathered customer on Rider OT elects Rider S, AmerenIP will purchase any remaining banked gas at the average market price for the year. If a grandfathered customer chooses Rider T, AIU states that the customer will have to deliver an appropriate amount of gas on a daily basis to the AmerenIP system to cover its usage.

In response to Staff's claim that Rider OT should not be eliminated because it provides a valuable service, allows for monthly balancing, contains no daily metering requirement, and provides system back-up service, AIU notes that only 87 customers are taking this service. While Staff acknowledges this is a small percentage of the total customer base, it claims that this may be an indictment of the current service offerings. AIU contends that this argument makes no sense since AmerenIP's current service offerings provide for bank services and extreme tolerance levels--both of which Staff claims are sorely needed by transportation customers. AIU also observes that Staff's proposed bank services and tolerance levels are not much different than what is currently being offered. To accept Staff's position on Rider OT, AIU continues, it follows that Staff's own proposal falls short.

b. Staff's Position

Staff witness Sackett recommends that the Commission reject AIU's proposal to eliminate AmerenIP's Rider OT. He contends that Rider OT should be retained because it provides a valuable service to transportation customers by giving customers an option between a service designed for large customers (Rider T) and one that allows for monthly balancing, no daily metering requirement, and system back up, all of which are ideal for smaller customers (Rider OT). In the previous gas rate case, Docket No. 04-0476, he notes that the Commission accepted AmerenIP's proposal to eliminate the banks for Rate 76 in part based upon AmerenIP's argument that those services were available under Rider OT. He believes that that policy goal of maintaining a banking storage service option for transportation customers is as important now as it was when the Commission entered its Order in Docket No. 04-0476. Indeed, Mr. Sackett continues, it may be more important now; without Rider OT, all customers, regardless of size, are forced onto the proposed Rider T.

Contrary to AIU's assertion, Mr. Sackett argues further that the services under Rider OT are valuable to transportation customers. He maintains that the fact that 87 AmerenIP customers currently pay for the services demonstrates that Rider OT is valuable. While 87 customers represents a small percentage of the total customer base for which the service is available, Mr. Sackett contends that this may be more of an indictment of AIU's current service offerings than an indication that a particular service has no value. He fears that AIU's current transportation service will become even less attractive if AIU's proposed reductions in services are approved. Mr. Sackett recommends that the Commission focus on the level of service that transportation customers receive and how much it costs. If the Commission adopts his proposals, he asserts that AIU's transportation service will become a better value, and it is likely that more customers will switch to transportation service.

Staff also notes that AIU's primary objection to Rider OT is that it —allows customers essentially to switch back and forth between system sales gas and transportation service . . . ." (Ameren Ex. 16.0 at 40) Staff notes further that AIU opines that such an option invites economic gaming by participating customers in a manner that burdens the operation of an efficient system. Staff states that AIU made both an economic argument about gaming and this operational argument, but failed to prove either of them.

With regard to AIU's "grandfather proposal" for Rider OT, Mr. Sackett does not consider it to be an adequate response to his concerns. He notes that under the grandfather proposal the services would still change to Rider T services, eliminating many of the advantages of Rider OT to customers and, thus, be detrimental to Rider OT customers. Mr. Sackett recommends retaining Rider OT services entirely and increasing its rates across-the-board. In light of the value of Rider OT to AmerenIP customers, he goes on to argue that if the Commission approves tariff standardization at this time, a similar service provision that appeals to smaller customers should be offered in all three service territories.

c. GFA's Position

GFA opposes eliminating AmerenIP's Rider OT. GFA contends that AIU's proposal is just one example of its willingness to make tariff structure changes to favor its own natural gas supply. Despite AIU's claims to grandfather Rider OT, GFA states that AIU's plan only retains monthly rate values increased by the proposed across-the-board percentage increase. All other terms and conditions, GFA notes, will be pursuant to Rider T provisions. GFA asserts that AIU's Initial Brief is misleading where it states that the benefit of grandfathering is the ability to satisfy existing customers on the rate while not allowing additional customers to be added to the rate. According to GFA, the benefits of Rider OT are actually stripped by AIU's proposal to make all Rider OT terms and conditions to be pursuant to Rider T. GFA states that AIU recognizes that tariff conformity across three service territories will eliminate certain provisions enjoyed by certain customers, but AIU again is only willing to conform tariffs when it is favorable to its own natural gas supply.

d. Commission Conclusion

AmerenIP's Rider OT does appear to have some benefits for smaller transportation customers, as Staff argues. In light of the Commission's earlier conclusion on storage banks and subsequent conclusions on daily telemetry and a small volume transportation tariff, however, the Commission does not believe that Rider OT remains a necessary vehicle for delivering those benefits to small transportation customers. Storage banks will also continue to exist for larger transportation customers and thus will not be needed under Rider OT. Grandfathering Rider OT for AmerenIP customers currently taking service under it appears to be of little benefit as proposed by AIU and thus is not adopted. Elimination of AmerenIP's Rider OT in conjunction with the other rate design conclusions in this Order promotes uniformity in the tariffs of the three gas utilities without unduly sacrificing service to transportation customers. Accordingly, AIU's proposal to eliminate AmerenIP's Rider OT is approved.

4. Elimination of AmerenCIPS' Stand-by Reserve

a. AIU's Position

Of the three AIU gas utilities, only AmerenCIPS currently offers SBR service. AmerenCIPS provides SBR through its existing Rider T. SBR is a service that provides for full or partial system back-up during periods of curtailment. Customers desiring SBR service elect what portion of their gas load that they would like available during periods of curtailment. AIU proposes to eliminate AmerenCIPS‘ SBR service, claiming that few customers want this service and eliminating it will achieve consistency among the three gas utilities.

AIU acknowledges Staff's claim that 50% of eligible AmerenCIPS customers (74 customers) have or want SBR service and that it should continue to be offered. In response, AIU assets that Staff‘s analysis is in error. AIU states that Mr. Sackett combined the number of Rider T and Rider S customers to determine the number of customers wanting SBR service. AIU notes, however, that he only used the number of Rider T customers to derive the percentage currently utilizing a designation amount greater than zero. Of those eligible for a partial designation, AIU contends that 0.4% actually utilize a designation greater than zero, rather than 20% erroneously claimed by Staff. Ameren Exhibit 30.7 shows the SBR option statistics for customers with Rider T, Rider S, and a combination of Rider T and S.

AIU note further that prior to its 2002 rate case, Docket No. 02-0837, AmerenCILCO offered a SBR option called daily limited firm backup ("DLFB"). AIU reports that in that rate case, the service was eliminated due to limited participation by transportation customers. Additionally, AIU states that the elimination of DLFB was uncontested by all parties, including Staff.

Furthermore, AIU contends that there are not enough pipeline capacity resources in the Midwest to offer SBR service, which has its origins in the 1980‘s, when transportation services were new and untested. AIU explains that SBR was originally designed during the initial unbundling of transportation services to give a back-stop to the new and untested transportation services then being offered. Because it targets a reserve margin (available firm deliverability resources over a design peak day) of 3% for load growth between capacity agreement terms, statistical errors in modeling the peak design day, and minor customer switching, AIU asserts that it simply does not have any extra firm resources on a peak day to offer a SBR option. As evidence of the lack of capacity, AIU relates that the newest interstate pipeline under construction in the U.S., the Rockies Express Pipeline, is fully subscribed before going into service.

If it is forced to offer a SBR service for all transportation customers, AIU states that an additional 490,000 MMBtu of firm transportation capacity potentially would be required, at a cost of over $74 million. AIU does not believe that it could secure this much firm capacity even if it wanted to, which makes Staff's request for this service a moot point. AIU adds that when a customer chooses to take transportation service, it is accepting the responsibility to secure its own gas supply and upstream transportation capacity resources, especially for a peak day. AIU insists that it should not be obligated to contract for supply services to serve as a back stop for transportation customers.

b. Staff's Position

Staff argues that AIU's proposal to eliminate AmerenCIPS' SBR service is another example of AIU's efforts to ―standardize" the service offerings among the AIU LDCs, but which reduce services for transportation customers. Mr. Sackett recommends against allowing the elimination of this service. According to Staff, SBR service recognizes the need for operational flexibility and is a valuable service to transportation customers which should be retained as a cost-based service option. Staff adds that SBR service will become even more valuable if curtailments become more common due to the increasing pipeline constraints that AIU predicts. In that eventuality, Staff states that SBR would serve as a functional mechanism to ensure gas supply to customers when needed. Moreover, rather than eliminating the AmerenCIPS SBR option, Mr. Sackett recommends standardizing AIU's tariffs by offering SBR in all three service territories.

Mr. Sackett contends that AIU has provided no compelling reason to eliminate SBR. In attempting to justify eliminating the AmerenCIPS SBR option, Staff states that AIU makes two mutually exclusive arguments. First, Staff notes that AIU questions the popularity of SBR service among eligible customers. Then, Staff continues, AIU argues that it would not be feasible to provide SBR service if all customers that would be eligible took full backup under it.

Staff asserts that AIU's argument about SBR's lack of popularity is off the mark because its calculation includes the total number of commercial and industrial sales and transportation customers served by AmerenCIPS. Staff calculates that 74 AmerenCIPS sales and transportation customers are paying for a partial designation of greater than 0%. Staff contends that it is evident from their willingness to pay for SBR that they find it beneficial. Staff adds that there is no indication that the costs of SBR are not being recovered from the customers electing this service. Furthermore, Staff argues that the popularity of SBR can be most appropriately determined by considering the percent of Rider T customers taking SBR. These are transportation customers and therefore are the customers that Staff proposes should have access to the service from all three utilities. Staff asserts that according to AIU's own numbers, 20% of AmerenCIPS' transportation customers are designating a SBR amount greater than zero. Staff notes that transportation customers tend to fall in higher usage classes and may be subject to curtailment before the sales customers that are primarily in the lower usage classes.

Mr. Sackett concludes that it is inconsistent for AIU to on the one hand argue that the vast majority of AmerenCIPS' Rider T customers have elected a stand-by level of zero and on the other hand state that AIU could not find capacity to provide this service if all customers wanted this service at a full back-up level.

c. Commission Conclusion

The decision of whether to eliminate AmerenCIPS' SBR service is not easy. Clearly some customers find it useful enough to pay extra for it, as Staff asserts. At the same time, however, the Commission recognizes that pipeline capacity resources in the Midwest have become more constrained since the initiation of SBR service, as AIU argues. Upon weighing all of the arguments, the Commission is persuaded by AIU. As noted above, AmerenIP has no SBR option and AmerenCILCO's equivalent to the SBR service was eliminated in its 2002 rate case without dispute. In light of this historically declining interest in SBR service, the Commission does not believe that retaining AmerenCIPS' SBR service is warranted, let alone expanding it to all three gas utilities. Although it is unlikely that all customers taking SBR service would designate all of their load for the service, the Commission is also concerned about AIU's ability to secure capacity throughout its systems. Accordingly, AIU's proposal to eliminate AmerenCIPS' SBR service is approved.

5. Intra-Day Nominations

Generally, a nomination in the context of the gas industry is a request for a quantity of gas under a specific contract or agreement with a gas supplier. An intra-day nomination is a request for gas received during the same day on which the customer wants to take delivery of the gas. An intra-day nomination may also be a request for gas received after the normal nomination deadline for the following day. One or more intra-day nominations, while not mandated for all LDCs, are the industry standard.

The NAESB, and its predecessor the Gas Industry Standards Board, have developed various standards for the purpose of ensuring smooth and efficient operations between producers, pipelines, local distribution utilities, marketers, and others. NAESB is the industry forum for the development and promotion of standards which will lead to a seamless marketplace, and its process for development and implementation of standards is consensus-driven. Among the promulgations of NAESB is a recommendation that LDCs implement one or more of 4 intra-day nominations, specifically the Timely Cycle (before 11:30 AM on the day before flow), Evening Cycle (before 6:00 PM on the day before flow), Intraday 1 Cycle (before 10:00 AM on the day of flow), and Intraday 2 Cycle (before 5:00 PM on the day of flow). Intra-day nomination cycles provide transportation customers the ability to change nominations when necessary after the earlier deadlines have passed. The need to adjust nominations can arise for numerous unexpected reasons, including weather conditions, changes in a customer‘s production schedules, or pipeline or utility system disruptions. Many LDCs have either voluntarily or by mandate implemented certain of the NAESB intraday standards.

a. AIU's Position

AIU currently utilizes the Timely nomination cycle. AIU proposes the addition of one new intra-day nomination cycle for all three gas utilities to give transportation customers an additional option to adjust gas supply deliveries to minimize imbalances. AIU proposes to add a new intra-day nomination cycle at 4:00 PM on the preceding day and use its best efforts to accommodate other intra-day nomination changes. AIU is only willing to provide this additional nomination on normal business days.

In response to the suggestion that it provide all 4 NAESB nomination cycles, AIU urges the Commission to refrain from ordering it to do so. AIU argues that doing so is not necessary because other Illinois gas utilities do not offer all 4 NAESB nomination cycles, which suggests to AIU that there is no need for the additional cycles, that it presents an undue cost to ratepayers, and that there has been no credible demand for this service. AIU states that it will provide the 4:00 PM evening nomination and any other off-cycle nominations it is able to using its current staff and resources.

AIU reports that the majority of transportation customers and their marketers efficiently manage their nominations and have not requested intraday nomination deadlines. AIU states that it has worked with the transporters to support their occasional need to make late nomination changes. AIU adds that there is no credible proof that additional intra-day nominations will meaningfully assist utilities in managing imbalances on interstate pipelines. Furthermore, AIU will continue to provide nomination flexibility when possible, but indicates that it can not uphold a firm tariff obligation to provide intra-day nominations throughout all evening and weekends and holidays without providing additional staffing during the off business hours.

The need for added personnel, AIU continues, is not limited to handling the additional intra-day nominations. AIU relates that it must coordinate nomination changes with Gas Supply and Gas Control personnel in order to effectuate the changes. Offering intra-day nominations would require additional staffing during the off business hours for these groups as well. AIU operates a 24-hour Gas Control Center; however, it is staffed during off-business hours strictly for meeting the requirements of gas control and monitoring for the transmission system, on-system storage fields, distribution level operating pressures, and maintaining the integrity and safety of the systems.

With regard to CNE-Gas' contention that other utilities offer all 4 intra-day nomination cycles, AIU notes that CNE-Gas excuses Peoples, North Shore, and Nicor for not being among them because these utilities allegedly offer more flexible storage access. AIU responds that its proposed banking services and tolerance levels are comparable to what these other utilities have in place. Furthermore, AIU asserts that its storage assets are considerably more limited than what Peoples, North Shore, and Nicor have in place, as discussed by AIU witness Glaeser. According to Mr. Glaeser, Peoples and North Shore have considerably more “leased” storage than does AIU. Furthermore, AIU avers that Peoples and Nicor do not offer firm intra-day nomination cycle rights. AIU states that Nicor has a strict nomination deadline of 11:30 AM the day prior to flow, with no flexibility for late nomination changes. In the recent Peoples/North Shore rate order, AIU reports that the Commission rejected the same arguments made by CNE-Gas. Moreover, AIU indicates that the utilities which CNE-Gas utilizes for comparisons, such as Pacific Gas and Electric Company and Southern California Gas Company, offer little resemblance to AIU in terms of the size of the their distribution systems, customer base, and employee numbers and, in fact, are the largest gas distribution systems in the U.S.

b. Staff's Position

Staff recommends that AIU be required to implement all 4 NAESB intra-day nominations. Doing so, Staff argues, will assist each LDC in maintaining its balances on the interstate pipelines. Staff states further that the additional costs to provide this service could be passed through to transportation customers in rates in subsequent rate cases. Staff points out that AIU can change its pipeline nominations twice during the gas day, but is not willing to pass this flexibility on to its transportation customers.

In support of AIU's position that there is no demonstrated need for these additional nomination cycles, Staff notes that AIU argues that most of its transportation customers have not requested intraday nominations and most of them manage their nominations efficiently. Since AIU did not consult with its transportation customers about its proposed offerings, however, Staff believes that AIU's first argument has no validity. If AIU had sought input from its customers prior to filing its service revision, Staff submits that it may have discovered that they do want this service. Additionally, the fact that AIU spent three rounds of testimony arguing that its transportation customers do not efficiently manage their nominations as a basis for its recommended changes weakens AIU's second argument on this issue, according to Staff.

Staff also notes AIU's dislike of CNE-Gas' comparison of AIU to other LDCs that offer these nominations as firm rights. Although AIU dismisses two of the other utilities on the grounds that they are significantly larger, Staff observes that this leaves seven other utilities for comparison, many from the Midwest. Staff also believes that AIU's comparison to Nicor, Peoples, and North Shore on this issue is not valid because all of these utilities offer enough flexibility that intra-day nominations would be less critical for them.

c. CNE-Gas' Position

CNE-Gas states that transportation customers, like utilities, may benefit from the use of intraday nominations to avoid imbalances or for other operational reasons. To aid in doing so, CNE-Gas provides suggested tariff language incorporating all 4 NAESB intra-day nominations. CNE-Gas asserts that such intra-day nominations would be similar to what AIU's own internal gas supply personnel do, by using this capability to help maintain supply stability. CNE-Gas suggests that AIU should discontinue its unduly discriminatory treatment of transportation customers and instead provide them the same options for the same reasons AIU desires intraday nominations – to help manage its load requirements when unanticipated changes occur.

In response to AIU's observation that neither Nicor nor Peoples offers the 4 firm intra-day nomination cycles, CNE-Gas acknowledges that this is true and counters that both Nicor and Peoples provide transportation customers with greater, more flexible storage access. As CNE-Gas witnesses explained, many of these issues are interrelated. CNE-Gas contends that AIU's approach seeks to provide transportation customers with little flexibility on all the interrelated items, including both intra-day nominations and storage banks. In comparison, CNE-Gas states that Nicor offers no flexibility on intraday nominations, but substantially greater flexibility on the storage banks provided to transportation customers. In the recent Peoples case, CNE-Gas relates that the Commission authorized several tariff provisions granting greater flexibility to transportation customers such as intraday allocations, greater flexibility during delivery restrictions, expanded imbalance trading, and April through October daily storage injection rights of up to the average daily use in the parallel month of the previous year plus 0.67% of the customers Allowable Bank, with the ability to inject up to a customer‘s MDQ during the remaining months. With the added flexibility for transportation customers, CNE-Gas states that the Commission elected not to require Peoples to offer the greater flexibility of intraday nominations.

d. Commission Conclusion

The Commission appreciates the benefits that more intra-day nomination cycles could bring to AIU's gas distribution systems and the customers thereof. In light of uncertainties regarding the cost of implementing all 4 cycles, however, the Commission is not prepared to require AIU to provide all 4 at this time. To order AIU to provide new services in this rate case but defer cost recovery until AIU's next rate case is not appropriate. When preparing its next gas rate cases, AIU should determine the cost of providing all 4 nomination cycles and provide that information with its rate filing. The Commission would also hope that those favoring the addition of nomination cycles would offer evidence of specific/concrete benefits associated with additional nomination cycles. The Commission hopes to use such information to weigh the cost and benefits of implementing the 4 NAESB nomination cycles in AIU's next gas rate cases. In the meantime, the Commission approves of AIU's proposed 4:00 PM evening nomination cycle, in conjunction with its current Timely nomination cycle. The Commission also expects AIU to use its best efforts to try to accommodate any other off-cycle nominations it is able to using its current staff and resources, as it committed to doing.

6. Daily Telemetry

a. AIU's Position

AIU proposes to require customers taking service under GDS-4, GDS-5, GDS-6 (AmerenCILCO only) and Rider T to provide daily telemetry. AIU witness Glaeser explains that daily telemetry is needed so that AIU can be assured of timely communication of transportation customer usage. He states further that daily telemetry allows AIU to provide transportation customers and marketers with more current data since the meter can be interrogated on a daily basis after 9:00 AM, which is the end of the gas day in the natural gas industry. AIU indicates that transportation customers and marketers would now have access to usage data from the previous day rather than usage from two days prior to the current gas day. Mr. Glaeser testifies that the daily telemetry requirements can be met with a dedicated telephone line, which can be an extension of an existing line. The line, however, could not be used for fax or any other purpose.

In response to GFA witness Adkisson's argument that the expense is not needed for small to intermediate and off-season transportation customers, Mr. Glaeser testifies that notwithstanding each customer's individual size, in the aggregate their usage can have a meaningful impact on the operations of the distribution systems. He adds that this concern of undue impacts can be exacerbated with regard to the smaller captive distribution systems within AIU's overall distribution systems. AIU offers the Crawford County area, as well as the Franklin, Hamilton and Perry County areas as examples of captive distribution systems. AIU states that daily information on transporters' usage can serve to prevent negative system impacts for these particular areas. Mr. Glaeser also notes that the requirement that these sized customers be subject to the daily telemetry requirements is not novel--AmerenIP already requires daily telemetry for transportation customers served under Rate 76.

Mr. Glaeser testifies further that there is a real benefit to transportation customers and their marketers by having this information in that they can better avoid higher cash-out prices. Moreover, he opines that in this day and age when state and federal policies abound with regard to the need for energy efficiency and responsible energy usage, these customers should bear some obligation to take measures by which to ensure responsible energy management. He went on to explain that, as a matter of fact, many transportation customers and marketers are desirous of this daily usage information. He testified that when such information is not posted on the management system in a timely basis, numerous inquiries are received from these customers/marketers. Even marketers who manage customers with relatively small loads that include the GDS-2 and GDS-3 customers are desirous of access to daily usage information in order to manage the aggregated imbalances associated with their customers. AIU does not respond to GFA's suggestion that if daily telemetry is required, that its installation be delayed until after November 2008.

With regard to GFA's concern about the additional expense of telemetry, AIU describes how GFA misunderstands AIU's proposal with a discussion of AmerenIP and a GDS-2 grain dryer customer. GFA asserts that a sales customer will see the incremental cost for telemetry increase to $660 annually, whereas, if it is taking delivery service, as would a transportation customer, the overall annual increase is $1,345. AIU explains that for an AmerenIP GDS-2 customer taking service under Rider T, the incremental cost for daily telemetry does increase, by the overall across-the-board increase, to $660 annually, but the $1,345 amount includes the annual daily telemetry charges ($660), as well as the increase to all other rate components within the rate. Thus, according to AIU, a current grain dryer customer taking service under GDS-2, who would also be taking transportation service under grandfathered Rider OT rate structure, will see the same across-the-board increase in GDS rates as a customer receiving sales service. AIU asserts that the current grain dryer customer taking transportation service under AmerenIP‘s Rate 76 (proposed Rider T) will realize the same across-the-board increase in GDS rates as customers receiving sales service.

In response to Mr. Sackett's concern that a $55 per month charge for telemetry presents an economic barrier for smaller customers and may force some transportation customers to move back to system supply, AIU asserts that such claims are simply wrong. First, AIU states that nothing is unique or novel about this particular charge. AmerenCIPS currently charges $55 per month for the same equipment, and the AmerenIP Rate 76 Facilities Charge and Advance Metering and Telecommunications Charge total $37.75 per month. Second, AIU asserts that the evidence is that small transportation customers at both AmerenCIPS and AmerenIP are not being deterred by paying these monthly charges. AIU states that there are many customers taking transportation service and are paying these charges. AIU witness Warwick testifies that AmerenCIPS has 125 small transportation customers while AmerenIP has 182 accounts under its Rate 76.

AIU acknowledges 4 objections made by Mr. Sackett in response to Mr. Warwick‘s testimony: (1) the number of small customers taking transportation service are a small percentage of eligible customers, (2) the conclusions drawn stem from current metering differentials and not the proposed charges, (3) while the metering charge may not be a barrier for some smaller transportation customers, it could still be a factor for others, and, (4) while it may be economical for current customers, it may keep other marginal customers from benefiting from transportation services. AIU contends that it is readily apparent that the majority, if not all, of Staff's objections are speculative and not grounded in any credible evidence. Mr. Warwick testifies that less than 1% of the small transportation customers eligible take such service from AmerenCILCO, which does not require a telemetry charge, suggesting Staff‘s claim that more customers would be interested fails. Mr. Warwick also emphasizes that the magnitude of the telemetry charges is driven by the across- the- board revenue allocation such that each rate value, including the telemetry charges, are being changed equally by the across-the- board percentage change. Taken to its logical extreme, any increase in any of the AIU rates may cause major behavioral changes on the part of all of its customers but, of course, such a result is not realistic. AIU asserts that there are cost increases and the affected businesses become more efficient, reduce their own costs, or pass them along to their customers. AIU states that it is difficult to conclude that a charge of less than $2 a day would prevent a customer from utilizing transportation service.

b. Staff's Position

To the extent that daily balancing is not necessary, Staff sees no reason for daily telemetry. Staff is also concerned that the expense of daily telemetry may discourage some customers from becoming transportation customers. Staff also suggests that AIU apparently does not understand that some customers may not have an extra $660 or $660.00 per year for telemetry fees lying around. According to Staff, the additional fee puts marketers at a disadvantage because they not only have to beat the PGA cost, they also have to beat it by this additional amount as well. Staff adds that AIU witness Warwick testifies that other factors would affect a customer's decision to remain on sales service and that the move to daily balancing, the loss of a bank, the requirement for a dedicated phone line, and a reduction in a daily balancing could all be factors.

In response to AIU's claim that because some small customers are taking service with daily balancing and telemetry there must be no barrier for anyone, Staff argues that there may be many other smaller customers that are not taking transportation service because they can not get gas priced competitively enough to beat not only the PGA but also the costs associated with the daily balancing and cashout and the telemetry and metering charges. With regard to AIU's observation that AmerenCILCO does not have daily balancing and metering requirements but only a few transportation customers, Staff submits that it is really AIU's unfavorable policies that keep customers, especially the small ones, from finding transportation service to be desirable. Staff fears that the number of transportation customers is likely to grow smaller if AIU's restrictive proposals are approved.

c. GFA's Position

GFA understands that daily telemetry is a useful and necessary tool for large users to manage the system's daily operation, but contends that daily telemetry is not necessary, nor an industry standard, for predictable small to intermediate users. For example, GFA states that telemetry requires the additional cost to obtain and maintain metering equipment. In addition, the user will pay one-time installation costs as well as the monthly cost of a dedicated phone line. On top of those costs, the user will incur additional administrative costs to manage the daily use data. GFA argues that all of these costs are justified for large users who need to manage the daily operation of the system, but are simply too large and disproportionate to the use of small and intermediate users. Indeed, GFA continues, the large cost results in an economic incentive for transportation users to switch to AIU supply. For example, under AIU's proposal, GFA reports that a small AmerenIP GDS-2 grain dryer customer under sales service will see its incremental cost for telemetry grow to $600 or $660.00 annually. If it is taking delivery service, its overall increment, compared to sales service, will increase to $1,345.00.

GFA disagrees with AIU's assertion that daily telemetry information helps transportation customers avoid higher cashout prices. The fallacy of that statement for a small grain dryer is obvious, according to GFA. GFA explains that the additional cost of AIU's filed tariffs has a bias in favor of its sales service supply by $2.24 per dekatherm relative to transportation service, which far exceeds what a small customer could expect to make up by avoiding higher cash-outs. In response to AIU's claim that some GDS-2 and GDS-3 customers or marketers would like to have daily usage information, GFA states that daily telemetry should be an option for those willing to pay for it.

GFA states that AIU's purported justification is that it would be nice to have daily telemetry to be able to monitor actual usages and manage imbalances in the system. AIU also suggests that it is good ―overall energy policy" to require daily telemetry. All of that, GFA asserts, ignores the significant, and hugely disproportionate, cost to the small to intermediate users. Instead of being good overall energy policy, GFA views this proposal as a thinly veiled attempt by AIU to force transportation customers to take AIU supply.

To see the lack of necessity for daily telemetry, one need look no further than other suppliers within Illinois, as well as the rules applicable to Missouri and Iowa utilities, according to GFA. Nicor, Peoples, North Shore, Mid American Energy Company, and AmerenCILCO currently offer small volume transportation service without telemetry. The State of Missouri, GFA states further, prohibits telemetry charges for small volume transportation for Missouri schools, which is applicable to AmerenUE, Laclede Gas Company, Missouri Gas Energy Company, Atmos Energy, Aquila, and any other utility regulated by the Missouri Public Service Commission. (See 393 Mo.Rev.Stat. §393.10) Furthermore, GFA reports that the Iowa Utilities Board recently ordered all Iowa investor-owned utilities to offer small volume transportation service without telemetry to all non-residential customers. These other utilities and state statutes and rules demonstrate that daily telemetry for the small to intermediate users is simply not necessary.

d. Commission Conclusion

The Commission understands AIU to propose that all Rider T transportation customers and all sales customers taking service under GDS-4, GDS-5, and GDS-6 (AmerenCILCO only)[13] to provide daily telemetry. Transportation customers otherwise eligible for service under GDS-2 and GDS-3 would provide daily telemetry under Rider T. Sales customers under GDS-2 and GDS-3 would not be required to provide daily telemetry.

The Commission agrees with AIU that daily telemetry can provide useful information, but does not understand the sales vs. transportation distinction that AIU draws between customers eligible for GDS-2 and GDS-3 service. The record lacks any explanation for why daily telemetry is not necessary for small sales customers but is for small transportation customers. In light of the cost of daily telemetry, the Commission views the proposed requirement on small transportation customers as a deterrent to taking transportation service. Accordingly, AIU may not require all transportation customers otherwise eligible for service under GDS-2 and GDS-3 to provide daily telemetry. Nor may AIU require small seasonal gas transportation customers otherwise eligible for service under GDS-2 or GDS-3 to provide daily telemetry. AIU shall, however, offer a daily telemetry option to such transportation customers in the same

[13] AmerenCIPS and AmerenIP do not have a GDS-6 rate class.

manner that other, larger transportation customers provide daily telemetry or on more favorable tariffed terms to the customer if costs prove to be less for smaller customers. AIU's proposal to require remaining Rider T customers and GDS-4, GDS-5, and GDS-6 customers to provide daily telemetry appears reasonable and is approved.

7. Small Volume Transportation Tariff

a. Staff's Position

Staff witness Sackett recommends implementing a small volume transportation tariff for all three utilities if the Commission determines that tariff standardization is appropriate at this time. He suggests a transportation service that balances monthly and does not require daily metering for smaller customers. He asserts that daily metering and balancing are unnecessary for smaller customers because they do not place the same constraints on the system as large customers. Mr. Sackett states further that no metering charge should be assessed beyond what these smaller customers would need for system supply service. With regard to telemetry, if the customer would not need telemetry as a sales customer, he does not believe that the customer should be required to have telemetry as a transportation customer.

Mr. Sackett notes that AIU already offers daily balancing and no telemetry in AmerenIP‘s territory under Rider OT and under existing Rider T in AmerenCILCO‘s territory. Therefore, he suggests that it should not be unduly difficult to add this to AmerenCIPS‘ tariff, as well. Mr. Sackett contends that AIU did not respond in either its rebuttal or surrebuttal testimony to his proposal to add a small volume transportation tariff for all three utilities. Since no party objected to this recommendation in their testimony, he asserts that the Commission should adopt it (if the Commission adopts tariff standardization).

b. AIU's Position

AIU objects to the implementation of a small volume transportation tariff and opposes monthly cash-outs for any sized customer. In addition, AIU finds Staff‘s position regarding proposed monthly cash-outs for small volume transportation customers to be at odds with Staff's own take on the benefits of daily cash-out. Specifically, AIU notes that Mr. Sackett agrees that daily cash-outs would help to eliminate gaming as part of his argument that bank services should remain. AIU adds that Mr. Sackett's position is consistent with Staff's position in AmerenIP's last gas rate case, Docket No. 04-0476. According to the Order in Docket No. 04-0476, Staff agreed with AmerenIP that daily balancing would prevent a certain amount of gaming in the monthly balancing and cash out procedures. (Order at 90)

c. GFA's Position

GFA expresses discontent with AIU's transportation tariffs. GFA states that it sponsors a natural gas purchasing and transportation pool for its members. These members are predominantly small and intermediate size grain dryers. GFA witness Adkisson testifies that its members are seriously considering switching to sales service with AIU supply because the proposed AIU transportation tariffs are so onerous.

d. Commission Conclusion

The Commission has considered the arguments for and against a small volume transportation tariff and concludes that the proposal has merit. Staff has persuaded the Commission that a simple straight forward transportation tariff for customers eligible for service under each utility's GDS-2 and GDS-3 rate classes is reasonable, including small seasonal customers taking service under GDS-5 who are otherwise eligible for service under GDS-2 and GDS-3. The tariff, which may be either part of Rider T or a separate tariff, shall provide for monthly balancing and not require daily metering. The Commission does not perceive a need at this time for anything more than monthly balancing for smaller customers. No metering charge should be assessed beyond what these smaller customers would need for system supply service. As discussed above, smaller transportation customers will have an option of utilizing daily telemetry. The Commission anticipates that this determination will make transportation service more available to small customers. The Commission would welcome an evaluation of the small volume transportation tariff from AIU, Staff, or any interveners in AIU's next gas rate cases.

8. 12-Month Notification for Seasonal Customers

a. AIU's Position

Both AIU‘s existing tariffs and its proposed Rider T require customers to notify AIU by July 1 of each year if they wish to change to or from transportation service effective the following November 1. Because the order in this proceeding will come after July 1, 2008, AIU proposes a later date for the year 2008 by which a notice of service change must be given. Specifically, eligible customers must provide notice of their choice by the later of October 17, 2008 or 14 days after compliance tariffs become effective.

As a compromise, AIU proposes, due to the unique nature of grain dryers, to change seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year. The general tariff requirement to remain on this rate for 12 months would not change. AIU believes that the proposed offer to change the notification date to April 1, with the sales service to be effective August 1 of the same year, would resolve the timing issue identified by GFA. AIU clarifies that it will continue to offer other transportation customers the one-time right to change the election for sales service before October 17, 2008, and will notify customers of this option through e-mail and AIU's internet-based USMS, which is an on-line management software system used to maintain daily usage, nominations, and billing information.

In making the proposed compromise to require notification by April 1, AIU does not fully accept Staff's position or any of GFA's various proposals. Rather, AIU contends that its proposal represents a reasonable accommodation to certain seasonal users, such as grain dryers and some asphalt plants, with production in later summer and fall. Expanding the notice compromise to all customers with low winter usage, as Staff and GFA propose, or to all customers who qualify for GDS-5 (as opposed to those who take service under the tariff) is not appropriate, according to AIU. As AIU witness Glaeser explains, off-seasonal use transport customers can create detrimental system impacts if not managed properly. Some of the firm transportation capacity contract levels for AIU ratchet down during the shoulder months, including September and October, when grain dryers typically have heavy usage, in order to follow the load shape of the system sales customers. Additionally, AIU states, this transportation capacity is used at high load factors during the shoulder months and summer to transport gas supply for storage injections into off-system and company owned storage facilities. AIU asserts that capacity for its systems can and does become constrained throughout the year, not just during the peak winter season. AIU contends that this is evident by the pro-rata reductions in primary firm transportation capacity on Panhandle Eastern in May 2008. As a result, AIU claims that allowing all customers with low winter usage to provide 4 months notice, as proposed by Staff (or 30 days as proposed by GFA) would be detrimental to AIU's planning for winter season usage. An April 1 notification date, for service on August 1, would address the GFA's concerns about the impact on grain dryers during the drying season. Therefore, AIU concludes that its compromise to change the seasonal rate class GDS-5 to require notification to AIU by April 1 to be effective August 1 of the same year is reasonable and should be adopted.

b. Staff's Position

While AIU's July 1st notice proposal makes sense for those customers needing to use most of their gas during the winter months, Staff states that it makes little sense for customers who will have little impact during those same months. Therefore, Staff witness Sackett recommends that all customers with less than 5% of annual usage occurring during December through March be required to provide a four-month advance notice before moving between system and transportation service regardless of the GDS that they take service under. Mr. Sackett's four-month notice proposal preserves the four-month notice period currently in effect and in proposed Rider T. Staff asserts that this proposal allows for notice to be provided at the beginning of the injection season for grain dryers.

Staff understands AIU to have accepted at least part of Staff's recommendation. Staff notes, however, that there are two important distinctions between AIU's proposal and Mr. Sackett's recommendation. AIU's proposal only addresses those customers on GDS-5 and it will be for April 1st instead of four months. Mr. Sackett's proposal would apply to all customers with less than 5% of annual usage occurring during December through March and would be a four-month notice. Thus, AIU's proposal would only benefit grain dryers with the four months and not work for other seasonal users whose usage does not pattern the grain dryers. AIU witness Glaeser admitted that his proposal does not address all of Mr. Sackett‘s concerns. Since AIU acknowledges that its position does not address all of Staff‘s concerns, Staff argues that AIU‘s proposal should be rejected and Staff‘s should be adopted.

c. GFA's Position

GFA finds the October 17, 2008, special one-time notice offer under proposed Rider T a problem for grain dryers for the 2008 harvest, which will already be in progress, if not nearly over. Even more importantly, for off-season users, the proposed on-going July 1 notification is a major problem beyond 2008, according to GFA. GFA is concerned because AIU's proposal requires grain dryers to give notice two harvests in advance. For example, the September-October, 2010, harvest is within the 12-month period beginning November 1, 2009, and ending October 31, 2010. As proposed by AIU, GFA states that GDS-2 and GDS-3 customers would be required to give AIU notice regarding the 2010 harvest by July 1, 2009. That notification date, July 1, 2009, occurs before the 2009 harvest. AIU‘s proposed notice requirement results in small and intermediate grain dryers having to give notice two harvests in advance. GFA complains that this proposal will require grain dryers to decide by July 1, 2009 their gas usage that will not begin until some 14 months later, in September of 2010. GFA avers that attempting to make that determination so far in advance will be difficult and risky. Rather than take that risk, GFA states that many grain dryers will likely just change to AIU supply. GFA maintains that the notification requirement is yet another method by which AIU is attempting to influence transportation customers to switch to AIU supply.

GFA states further that AIU will not offer to GDS-3 and GDS-4 customers the reasonable notification requirements available to GDS-5 customers. GFA observes that for seasonal GDS-5 customers, AIU has offered to change the notification requirement to April 1 to be effective August 1 of the same year. GFA asserts that does not solve the issue for smaller to intermediate seasonal use grain dryers. Unless and until AIU‘s GDS-5 tariff is designed for small and intermediate, as well as large users, GFA states that most dryers with seasonal use that qualify for GDS-5 can not economically take GDS-5 and therefore take service under GDS-2 or GDS-3 tariffs. Those GDS-2 and GDS-3 customers are not being offered the April 1 notification to be effective August 1, despite having the same seasonal use pattern as GDS-5 customers.

GFA proposes that the GDS-5 notification provision (April 1 notice to be effective August 1) be applicable not only to GDS-5 seasonal customers, but to all seasonal customers that qualify for GDS-5, whether or not they choose to take service under GDS-5 (such as grain dryers who choose to remain on GDS-2 or GDS-3). GFA suggests that this proposal would eliminate the discrimination against small and intermediate seasonal users. Alternatively, GFA proposes that seasonal use customers, with less than 5% of annual use in the months of December through March, should not be required to stay on transportation service for 12 consecutive months. Instead, such users could stay on transportation service through March if transportation service commences after December 1 and before April 1. GFA states that both of these solutions would alleviate the harshness imposed with the two harvest notice requirements proposed by AIU.

d. Commission Conclusion

At a minimum, grain dryers under GDS-5 should be allowed to provide notice by April 1 of each year whether they intend to be a transportation customer or sales customer beginning August 1 of that same year, on which AIU, Staff, and GFA all appear to agree. Whether other seasonal users of gas eligible for service under GDS-5, regardless of whether they actually take service under GDS-5, should be able to operate under the same notice provisions is less clear. AIU appears to have legitimate capacity concerns in conjunction with allowing all small and intermediate seasonal users to provide April 1 notice of a switch between sales and transportation service. Although the Commission does not adopt such a broad application of the April 1 notice provision in this proceeding, the Commission is interested in considering this idea further and invites discussion of it in AIU's next gas rate cases. In the meantime, however, given the nature of grain dryers' seasonal use, the Commission finds that grain dryers under GDS-2 and GDS-3 should also be allowed to provide such notice by April 1 of each year, for the period beginning the following August 1. With regard to waiving or modifying the general tariff requirement that grain dryers remain on the rate for 12 months, the Commission is not prepared to do so at this time in absence of assurances that gaming would not occur.

9. Minimal Winter Use Delivery Service Provisions

a. AIU's Position

With respect to AmerenCIPS, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 3 and Rate 4. With respect to AmerenCILCO, AIU proposes removing the Minimal Winter Use delivery service provisions from the present Rate 600. In both instances, AIU proposes to include such language in its proposed new GDS-5 -- Seasonal Gas Delivery Service.

AIU also asserts that upon reviewing Staff's Initial Brief, it learned of several new and significant changes in gas rate design related to —seasonal load" being recommended by Staff (discussed below). AIU states that Staff's recommendations lack supporting citations to the record as to their scope, applicability, or impacts on all affected customers. AIU goes on to state that the novel changes recommended by Staff are extremely problematic as well as markedly vague. All of the recommendations related to changes to accommodate —seasonal load." AIU contends, however, that Staff fails to provide a definition of —seasonal load" in its Initial Brief. Because natural gas is used for heating, AIU observes that a large number of all customers use natural gas seasonally. AIU maintains that it is unclear from Staff's recommendation what the parameters of —seasonal" use would be.

Additionally, AIU avers that converting demand charges to volumetric charges involves a major change in rate design elements. AIU also notes that a major theme in Staff's rate design testimony is its assertion that all rates for customers should increase equally across-the-board to the extent feasible. AIU argues that converting a demand charge to a volumetric charge is inconsistent with that theme because doing so will result in unequal customer impacts. Finally, AIU insists that Staff's assertion that AIU has not provided credible support for why customers should require demand charges is incorrect. AIU contends that it provided ample expert testimony on the subjects of telemetry and the inappropriateness of eliminating demand rates.

b. Staff's Position

In response to AIU's proposal to include the Minimal Winter Use delivery service provisions in GDS-5, Staff witness Harden agrees that doing so is an appropriate means of conforming AIU's gas rate classes with its electric rate classes since it would not result in unequal bill impacts for individual gas customers. In its Initial Brief, Staff also voiced support for various GFA proposals concerning seasonal usage. GFA argues that seasonal customers do not place constraints on the system and therefore should not be assessed a demand charge. GFA also wants a volumetric charge for any customer with a seasonal load profile. GFA proposes that it should not be required to have daily balancing and telemetry as well. AIU witness Glaeser presents a counter-argument concerning an isolated incident where on one captive system, a single seasonal customer, has more than half of the load on that system.

Staff contends that AIU is attempting to use anecdotal evidence to prove that it must take a certain course of action. In this situation, however, Staff argues that AIU's example is not even close to being representative of the typical grain dryer. The one customer that it used, Staff notes, was not even a grain dryer. Another reason that Staff believes that AIU's response should be dismissed is because the issue is not directly related to these customers being transportation customers. Staff contends that the situation of the customer Mr. Glaeser used in his example would be the same if it were a sales customer, because its load is still unpredictable and the size of its usage relative to the captive system load would not change. Some exceptions may require daily metering, but AIU has provided no reason to conclude that most seasonal customers place such a load on the system that they need either daily balancing or telemetry, according to Staff. Staff therefore recommends that the Commission adopt GFA's proposal that customers with a seasonal load should not be required to balance daily and have daily telemetry regardless of which GDS they would otherwise be on. Also, because AIU has failed to provide a credible rationale for why seasonal customers should have demand charges, Staff recommends that the customers who would not be required to have a demand charge under the non-seasonal GDS classes, should not face a demand charge under GDS-5.

c. GFA's Position

GFA recommends that the demand charges in GDS-2 and GDS-3 be converted to volumetric charges, a recommendation which AIU opposes. GFA argues that non-winter seasonal use customers do not place constraints on the AIU distribution system, and therefore should not be charged a demand charge. GFA states further that AIU has not provided evidence that a demand charge, particularly a year-round demand charge, is appropriate for customers with minimal winter use (less than 5% of annual usage occurring during December through March). GFA observes that Mr. Glaeser uses a single anecdotal example of a seasonal customer on a captive part of the AIU distribution system (one pipeline supply). Because AIU's distribution system capacity is obviously underutilized during non-winter periods, GFA asserts that there is no justification for AIU to require demand charges for small and intermediate use customers with minimal winter use. GFA finds Staff's reasoning sound when it recommends that customers who would not be required to have a demand charge under the non-seasonal GDS rate schedules should not face a demand charge under the GDS-5 seasonal rate.

d. Commission Conclusion

AIU's proposal to include the Minimal Winter Use delivery service provisions from AmerenCILCO's Rate 600 and AmerenCIPS' Rates 3 and 4 in the new proposed GDS-5 does not appear to be opposed by any party. This proposal is reasonable in the Commission's opinion and is adopted. Other issues under this heading are less clear.

The elimination of the demand charge for non-winter gas customers as well as minimal winter use customers is an intriguing idea, but without more information, the Commission is not prepared to adopt these proposals at this time. One concern that causes the Commission to hesitate in adopting this proposal is the uncertainty surrounding the degree to which non-winter gas users affect the apparently increasing non-winter demand for gas. The ease/difficulty of converting demand charges to volumetric charges is another area of concern for the Commission. Without knowing more about how this would be accomplished, the Commission is reluctant to direct that it be done. The Commission invites further discussion on these issues in AIU's next gas rate cases.

With regard to daily balancing and telemetry for customers on GDS-5, the Commission is not persuaded at this time that such are not appropriate for larger sales or transportation seasonal customers. Accordingly, the Commission rejects Staff's and GFA's proposal that larger seasonal customers be free of any requirement to use daily balancing and telemetry. As discussed above, however, in the general discussions of daily telemetry and a small volume transportation tariff, the Commission is of the opinion at this time that daily balancing and telemetry are not necessary for transportation customers who would otherwise be GDS-2 and GDS-3 sales customers. Similarly, the Commission does not believe at this time that GDS-2 and GDS-3 sales customers should be required to provide daily balancing and telemetry. In the absence of any persuasive arguments to the contrary, the Commission sees no need for daily balancing and telemetry for such smaller seasonal customers.

10. Uniform Terms Among Tariffs

GFA witness Adkisson is troubled by the fact that GDS-2, GDS-3, GDS-4, and GDS-5 have differing maximum use qualifications among the three utilities. He suggests implementing uniform use qualifications among corresponding GDS rates for all three utilities. GFA notes that AIU cites the need for rate continuity and stability, as well as the need to make changes gradually. Although AIU proposes continuity and stability here, GFA asserts that AIU abandons those principals when it wants to make tariff changes. GFA contends that AIU's inconsistencies point to its attempts to influence customers toward AIU supply.

AIU does not find GFA's concerns on this issue valid. AIU states that its rate design objective was to conform rates to the maximum extent possible while still maintaining rate continuity and stability. According to AIU, Mr. Adkisson‘s recommendation to conform the GDS rate qualification provisions among the three utilities might compromise the AIU rate continuity and stability goal.

AIU points out that Mr. Adkisson provides no analysis of the effects (i.e., customer rate migration, revenue instability, customer bill impacts, or cost analysis) of his proposed recommendation. Without thorough analysis, AIU fears that constructing a different rate design would inappropriately expose it to possible revenue erosion and run counter to the way rate classifications are set today. AIU maintains that GFA's recommendations will require a complete analysis of the affected service classifications to determine realignment of class billing determinants, and also require estimates and assumptions made for expected customer migration.

If the Commission agrees with Mr. Adkisson's rate design recommendation, AIU states that the final rates would need to be developed only after a detailed analysis of the recommendation, so as to determine the respective billing units for each affected service classification. The determination of billing units would also need to take into consideration the effects of rate migration, if any. AIU argues that this process would be necessary to ensure that, at the end of the day, the compliance rates filed in the case provide AIU with a reasonable opportunity to earn the rate of return granted in this case. AIU adds that the Commission would have to allow adjustments to other rates in order for the utilities to make-up any revenue shortfall created by his proposal.

The Commission understands GFA‘s concern. While some consistency exists among the maximum use qualifications for the GDS-2, GDS-3, GDS-4, and GDS-5 rate classes among the three utilities, obvious inconsistencies also exist. The Commission would also prefer that these tariffs be much more similar. Because this is the first "incarnation" of the GDS rate classes and because no analysis of the effects of more uniform GDS rate classes has been done, however, the Commission is not prepared to direct that AIU implement uniform maximum use qualifications for the GDS-2, GDS-3, GDS-4, and GDS-5 rate classes among the three utilities in this proceeding. Instead the Commission directs AIU to study the impact of GFA's proposal prior to its next gas rate case. If AIU finds that greater uniformity is warranted, its rate filing should reflect the results of that study. If AIU finds that greater uniformity is not warranted, it should be prepared to explain why and provide the results of the study if asked during the discovery process.

11. Weather Normalization

AIU calculated billing determinants in this case based on 10-year weather normalized averages. AIU witness Laderoute presents testimony showing that 10-year normals are a better predictor and more representative of ―normal" weather than 30-year normals in this case. He conducted a number of detailed statistical tests that are used by meteorologists and climatologists in studying weather and normals to test the validity of this conclusion, using historic National Oceanic & Atmospheric Administration weather data for Champaign-Urbana. AIU states that no party challenged the validity of Mr. Laderoute's testing, data, or conclusions.

In his direct testimony, Staff witness Sackett concluded that AIU's proposal to use a shorter weather period was acceptable, but recommended that AIU provide a weather study similar to that used in the Peoples/North Shore gas rates cases, Docket Nos. 07-0241 and 07-0242 (Cons.). He indicated that the weather study should provide additional weather normalization data sets between 8 and 12 years in length, and compare such sets with a 30-year data set to determine the predictive quality of each set. Mr. Sackett requested the information because he understood the Order in Docket Nos. 07-0241/07-0242 (Cons.) to require him to do so. Mr. Laderoute provided the requested data and analysis in his rebuttal testimony, and concluded that the 8-, 11-, and 12-year normalized data sets are comparable to the 10-year normals in this case, and are therefore more predictive than the 30-year normal results presented in his direct testimony. Mr. Sackett agrees that AIU's approach is reasonable and not inappropriate.

The only issue to address is whether the Order in Docket Nos. 07-0241 and 07-0242 (Cons.) requires all utilities in the future to provide additional data sets and compare such sets with a 30-year data set to determine the predictive quality of each set. AIU does not believe that the Commission has required utilities in all future rate cases to provide a range of data to support their chosen weather normalization period, to determine which is the most predictive. AIU contends that this interpretation would be cumbersome and unnecessary. AIU acknowledges that the Commission adopted a more predictive approach to weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.), to further the Commission's goal of setting ―rates with the greatest likelihood of generating the Utilities' allowed annual revenues." (Docket Nos. 07-0241 and 07-0242 (Cons.), Order at 123) Mr. Laderoute's recommendations, AIU adds, are consistent with this goal.

Understanding the background associated with this issue may facilitate discussion. In the Peoples/North Shore rate case, the Commission noted that it would have expected a 30-year data set to be more predictive, based on the general statistical principle that more data regarding varying conditions is better than less. But after having considered the 8-, 11-, and 12-year normals, as well as the evidence presented in Nicor's most recent rate case (Docket No. 04-0779), the Commission concluded that there was no stable long-term trend in weather that would justify adhering to a 30-year normal. Furthermore, in adopting a 10-year normal in the Peoples/North Shore case, the Commission did not adopt the most predictive weather data set. In that case, the Commission made a decision between the most predictive data sets presented in light of all of the evidence.

In this case, AIU has shown that 11-year normals appear to be the most predictive set, but that adoption of 10-year normals presents a similarly predictive result and is reasonable in this case. Although Mr. Sackett agrees with Mr. Laderoute, Staff asserts that AIU provided no reason why a 10-year normal is as good as or better than the 11-year normal. AIU merely concludes that because the 10-year falls between the 11-year and 8-year normal in length that it was, —on balance," appropriate. AIU also notes that all of its billing determinants and resulting rate design data in this case are based on 10-year weather normalized data. Parties have not had the opportunity to review and respond to rate design evidence developed using alternative heating degree days, from alternative weather norm data sets.

While Staff recognizes that the Commission is not bound by its prior decisions, it still maintains that all utilities must provide the additional weather data discussed in Docket Nos. 07-0241 and 07-0242 (Cons.). Staff points out that the Commission required that all subsequent rate cases follow the procedures it adopted in that case, stating that, —In subsequent rate cases, we will expect utilities to employ the principles and methods approved here or bear the burden of proving that additional measures will materially enhance the alignment of allowed and actual revenues." (Order at 125-126)

The Commission concludes that AIU's use of a 10-year weather normalized average is acceptable and is hereby approved. The Commission also appreciates Staff's observance of the conclusion on weather normalization in Docket Nos. 07-0241 and 07-0242 (Cons.). While it is correct that the decisions of the Commission are not <u>res judicata,</u> nothing prevents Staff or the Commission from recognizing the value of an earlier decision and applying the same principles to another proceeding. In this instance Staff sought additional information consistent with the weather normalization conclusion in the Peoples/North Shore Order in order to ensure that use of 10-year averages is appropriate. AIU provided the information and the primary question was resolved. To facilitate the resolution of this issue in future AIU rate cases, the Commission directs AIU to provide comparable data sets as it did in this proceeding with its initial filing. Staff is not barred from seeking other data sets for comparison purposes.

12. Imbalance Trading

a. AIU's Position

Prior to its decision in this proceeding to offer banking, AIU offered to provide an imbalance trading mechanism to transportation customers. AIU witness Glaeser explained that a transportation customer or marketer could monitor its imbalance position during the month through the USMS. Mr. Glaeser further explained that transportation customers could choose to contact another transportation customer or marketer served from the same interstate pipeline and trade off-setting imbalances. The parties involved in the trade would be required to provide confirmation that the trade, in fact, had been agreed upon. Thereafter, AIU would change each customer's imbalance position within the USMS. Mr. Glaeser went on to testify that modifying the USMS system in order to accommodate imbalance trading would take time, as significant software changes are needed.

AIU now contends, however, that subsequent developments in this proceeding have eliminated the need for the imbalance trading service. The imbalance trading mechanism was intended to help transportation customers and marketers manage daily imbalances in order to minimize daily and monthly cash-out charges. As Mr. Glaeser explains in his surrebuttal testimony, AIU is now proposing to offer banking services which satisfies the same objective. AIU adds that with the offer of banking services, the imbalance trading service is no longer needed since the bank balance can be transferred between transportation customers and marketers. Mr. Glaeser also explains that bank limit balances between transportation customers served by the same interstate pipeline are transferable after confirmation from both counterparties. As AIU moves from the current bank services offered under the existing tariffs to those that it now proposes, AIU states that any balance in excess of the new bank limit maximums will be cashed out at the average of the Chicago City Gate first of the month price for the prior 12-month period after the customer avails itself of any bank balance trading with other customers. Consequently, because proposed banking service fulfills the same purpose as imbalance trading service, AIU withdraws its imbalance trading proposal and urges the adoption of its proposed banking service.

AIU notes CNE-Gas' concern that the bank services may not sufficiently make up for the absence of imbalance trading. In response, AIU states that the requisite functionality will be provided. AIU also asserts that CNE-Gas' effort to tie AIU to a Peoples tariff should be disregarded. According to AIU, there has been no factual demonstration to show that AIU's systems can accommodate the specifics associated with the Peoples tariff.

b. Staff's Position

Staff understands that AIU is withdrawing its proposal to provide for imbalance trading on the grounds that it is no longer necessary in light of AIU's newly proposed bank balance trading. Staff states that AIU's proposal to trade bank balances does not directly affect the daily imbalances that customers face. Staff witness Sackett, however, agrees that, with any of the bank proposals, the need for imbalance trading is limited.

c. CNE-Gas' Position

CNE-Gas understands that AIU has withdrawn its imbalance trading service since AIU does not believe it is necessary with a banking service. CNE-Gas is concerned by this change but acknowledges that once actual tariff sheets setting forth the terms and conditions of the banking service are available for examination, the transfer of bank limit balances may provide some of the imbalance trading that transportation customers functionally require. Although the operation of imbalance trading may be different with and without a storage bank, CNE-Gas asserts that imbalance trading remains a valuable tool for transportation customers. CNE-Gas' concern is that even with storage banks, transportation customers need to have the ability to trade their bank imbalances with others. Whether this is called "Imbalance Trading" per se is not important to CNE-Gas; what is critical is that the functionality exists. CNE-Gas seeks functionality on par with that described in the Peoples/North Shore Order.

Although under the Peoples/North Shore Order imbalance trading is not allowed between customers of different utilities, for instance between customers of Peoples and North Shore, CNE-Gas indicates that there are no additional restrictions related to upstream pipelines. CNE-Gas states that this is one key distinction between imbalance trading, as discussed in the Peoples/North Shore Order, and the transfer of bank limits mentioned in Mr. Glaeser's surrebuttal testimony. Since imbalances offset one another under imbalance trading, CNE-Gas contends that AIU should be indifferent and there is no adverse impact on utility operations. CNE-Gas recommends that the Commission direct AIU to include imbalance trading, similar to the Peoples/North Shore Order described above, in its transportation tariffs.

d. Commission Conclusion

The Commission recognizes the value of imbalance trading to transportation customers. But given the adoption of gas banking services above, the Commission does not believe that imbalance trading is necessary under the circumstances. If circumstances change in future AIU rate cases, the Commission will again consider requiring imbalance trading.

13. Purchase/Confiscation of Customer-Owned Gas

a. AIU's Position

AIU's existing tariffs provide AIU the right to purchase gas owned by transportation customers in a situation where system integrity is threatened and the system emergency requires curtailment. AIU proposes similar language in its proposed Rider T. Under its proposal, AIU would first attempt to acquire the transportation customer gas through a voluntary purchase. If a voluntary purchase does not occur, proposed Rider T provides that AIU may confiscate the gas at price of 110% of the daily market price.

While CNE-Gas understands that AIU may need to acquire customer-owned gas in an emergency, it is still troubled by the idea of a forced sale of transportation gas even if a 10% premium is included. To address such concerns, AIU's current proposal contains three conditions that must be met before AIU has the right to purchase gas owned by transportation customers. First, system integrity is threatened. Second, the utility has declared a Critical Day. Third, the utility implements curtailment of natural gas service to customers pursuant to the Curtailment Plan. AIU contends that these conditions ensure that it will not arbitrarily acquire gas from its transportation customers without good reason and will exercise this right only under the most severe circumstances. AIU states further that the right to purchase gas owned by transportation customers would not be allowed only on a critical day since all three conditions must be met before purchasing customer gas. In addition, the proposed tariff states ―the Company's right to purchase gas owned by a Customer shall be exercised by the Company only after the Company has exhausted reasonable efforts to obtain the necessary gas supplies from other sources . . . ." (Ameren Ex. 30.0 at 30-31)

In response to CNE-Gas' assertion that involuntary confiscation of transportation gas supplies will not increase the volume of gas that is flowing during a curtailment, and therefore no relief will be provided, AIU asserts that CNE-Gas misunderstands how the process works. AIU witness Glaeser explains that volumes of gas delivered into the system during a curtailment will likely not be increased by confiscation; however, the needed relief is still provided. The gas purchases only occur during curtailment, during which customers will be required to reduce usage by customer class so that the demand on the system will be lower. The gas purchased from the transportation customers at the city gate delivery points will be then used to serve high priority residential and human needs customers, since the larger customers will have been curtailed.

If confiscation occurs, CNE-Gas argues that AIU should waive any balancing costs or penalties incurred due to any imbalance created when transportation customer gas is purchased during curtailment. AIU does not agree and argues that if a customer is complying with the curtailment, the imbalance will be minimized. AIU states that it would not buy any gas from transportation customers unless they have been curtailed, which means their usage has been reduced. If there is more than a minimal imbalance, AIU maintains that the customer has not complied with the curtailment and should incur all imbalance charges as well as penalties. If these costs and penalties are waived, AIU asserts that there is no incentive to a customer to reduce its usage, thereby defeating the purpose of the curtailment and thus threatening system integrity.

In response to any suggestion that confiscation of gas, even with a 10% premium, constitutes a conversion under 810 ILCS 5/7-404, AIU argues in its Reply Brief that this section of the Illinois statutes is inapplicable to that situation. Moreover, if such tariffs are approved by the Commission, AIU asserts that it would be difficult to claim that the tariffs are unfair since it is the Commission that determines what is fair in this proceeding. Taking the CNE-Gas position regarding conversion to its logical extreme, AIU contends that no gas utility could ever curtail or interrupt a transportation customer no matter what the circumstance. AIU also does not see the relevance of CNE-Gas' FERC discussion.

b. Staff's Position

AIU initially sought the right to purchase customer gas at market price on a critical day. Staff witness Sackett objects to this because he believes that AIU should attempt to purchase gas from transportation customers in voluntary transactions before confiscating gas from customers. CNE-Gas proposes that, at a minimum, a 10% premium be applied to the market price for that purchase. Mr. Glaeser then proposed a voluntary purchase offer first, and then confiscation at a 10% premium over the market price. Mr. Sackett accepts this proposal.

c. CNE-Gas' Position

CNE-Gas objects to any forced sale of customer-owned gas, no matter the circumstances. Confiscation of customer-owned gas, CNE-Gas opines, would likely constitute conversion under Illinois law. CNE-Gas reports that Section 7-404 of the Uniform Commercial Code (adopted as 810 ILCS 5/7-404 (2008) in Illinois) states that a bailee is not liable for delivering goods to a person who did not have authority to receive the goods if the bailee acts in good faith. However, the commentary to the provision states that "[g]ood faith now means 'honesty in fact and the observance of reasonable commercial standards of fair dealing,'" UCC §7-404 cmt. purposes (2007). CNE-Gas contends that AIU's confiscation of customer-owned gas would be unlikely to be considered good faith under this standard because AIU would have knowledge that the supplier did not wish to sell the gas to AIU. (See <u>Bishop v. Allied Van Lines 3 Dist., Inc.</u>, 399 N.E.2d 698, 701 (Ill. Ct. App. 1980) (holding that a bailee did not act in good faith and did not observe commercially reasonable standards when the bailee delivered the goods with knowledge of adverse claims between the bailors)).

Similarly, CNE-Gas states that FERC has required interstate pipeline tariff provisions that provide for the seizure of gas by the pipeline to be removed from tariffs if a customer fails to abide by a curtailment or interruption notice. (See, e.g., Guardian Pipeline, L.L.C., 91 FERC ¶61,285 at 61,987 (2000); TriState Pipeline, L.L.C., 88 FERC ¶61,328 at 62,006 (1999); Steuben Gas Storage Company, 72 FERC ¶61,102 at 61,543 (1995))

CNE-Gas also argues that because AIU does not propose to waive penalties for actions taken by transportation customers in support of a curtailment order, the confiscation of customer-owned gas supply leaves the transportation customer at risk of receiving a price of only 90% of index if it delivers excess supply, while nominated volumes are sold to the utility at 110% of index, even though both actions alleviate the curtailment. Even at the 110% index price, CNE-Gas states that transportation customers could be forced to sell gas to the utility at a financial loss, depending on the purchase price, which may not be index-based. As the daily market price is based upon the price that gas traded at the morning prior to flow, CNE-Gas contends that it is likely that by the time the Critical Day takes effect, as no advance notice must be provided, the daily market price from the previous day is no longer representative of the market price at that point in time when the gas is seized. The mechanics of this ultimately depend upon the exact storage, cashout, and balancing tariffs approved in this proceeding and since no draft tariffs exist for any of the current proposals offered, CNE-Gas simply requests that if the Commission approves the confiscation of the customer's gas supply, the customer should not be assessed any charges or penalties due to any positive imbalance that is created following a forced sale.

CNE-Gas states further that transportation customers and their suppliers may also have the option to secure additional gas supply. AIU's proposed tariff, CNE-Gas complains, does not accommodate such action. Instead such action could be met with additional costs and penalties from AIU, even though additional gas supplies on a Critical Day is precisely the outcome AIU desires. Consequently, if AIU's proposal is approved, CNE-Gas asserts that transportation customers should not be penalized or charged for delivering additional gas supplies under such circumstances. CNE-Gas urges the Commission to require waiver of such additional costs.

d. Commission Conclusion

At the outset, the Commission must state that it does not anticipate that AIU will often need to purchase or confiscate gas owned by transportation customers in order to preserve system integrity. In a well maintained and managed system, such circumstances should occur infrequently. Purchasing or confiscating customer-owned gas should be, and appears to be, viewed by AIU as a last resort to stave off an emergency.

The less extreme of the two options for avoiding an emergency is obviously a voluntary purchase. The Commission agrees with and approves of the notion that AIU should first attempt to negotiate a price for customer-owned gas that it seeks to acquire. In the event that a voluntary purchase can not be negotiated, the Commission also agrees that AIU should be able to confiscate customer-owned gas under reasonable terms in order to prevent harm to the gas distribution system. The Commission has considered CNE-Gas' claim that confiscation of customer-owned gas violates Section 7-404 of the Uniform Commercial Code, but does not find this statute applicable.

If AIU is permitted to purchase customer owned gas, CNE-Gas also argues that the transportation customer should not be penalized for any imbalances resulting from the associated curtailment. The Commission agrees with CNE-Gas to the extent that the imbalance is one where the transportation customer delivers more gas into the system than is used for this is exactly what a struggling system needs. If a transportation customer uses more gas than it delivers into the system, then the imbalance penalties should apply. As for the price of confiscated gas, the Commission is concerned that paying the transportation customer the market price of gas traded at the morning prior to flow may not be reasonable. If circumstances are such that curtailment and a Critical Day are occurring, the market price of gas may be quite higher than what it was the morning prior to flow. Therefore, the Commission concludes that the price to be paid for confiscated gas should be equal to the 8:00 AM index price reported by Platt's *Gas Daily* Midpoint for Chicago Citygates on the Critical Day. A 10% premium shall be added, as agreed to by AIU. This result should address transportation customers' concerns about receiving a fair price for confiscated gas.

14. Critical Day and Operational Flow Order Notice Provisions

a. AIU's Position

AIU proposes to include both Critical Day and OFO language in gas tariffs. AIU witness Glaeser explains that an OFO is an order which the utility may declare or issue to a customer group or to specific customers in order to alleviate problematic operating conditions. He also indicates that the new Rider T includes the Critical Day declarations. Mr. Glaeser identifies a number of circumstances that could cause the declaration of a Critical Day. The ―common driver" is that on-system or up-stream resources used to operate and maintain system integrity are under duress, threatening the integrity of the distribution system and the ability to deliver gas to all customers. AIU states that OFOs and Critical Day provisions are common place in the natural gas industry, including the interstate pipelines to which AIU is connected, and are necessary to ensure the integrity of the delivery system. AIU proposes that transportation customers be notified of an OFO or Critical Day through formal notification such as telephone, fax, or e-mail. The utility would also post such a declaration on its USMS website, which is utilized by transportation customers and their marketers for routine operations. Mr. Glaeser also identifies the various penalties and charges that would be issued in the event an OFO or Critical Day was violated. He explains that a series of tiered penalty charges tied to the severity of the event are being proposed and identified the three penalty charges as: OFO Balancing Charge, Unauthorized Gas Use Charge, and Critical Day Imbalance Charge. Mr. Glaeser also testifies as to the manner by which these charges would be assessed.

AIU notes that only CNE-Gas responds to AIU's OFO and Critical Day positions. Specifically, CNE-Gas is concerned with the lack of no advance notification requirements and argues that some parameters should be placed in the tariff to provide guidance for the type of advanced notice that the utilities will provide to the transportation customers and their suppliers. In response, Mr. Glaeser testifies that AIU is willing to provide a 2-hour prior notice before implementing an OFO against any customer or group of customers. He also testifies that as much notice as practical would be given to customers in the event of a Critical Day but that a defined time frame could not be provided due to the unexpected nature of the events that lead to a Critical Day declaration. As an example, Mr. Glaeser observes that a pipeline rupture foregoes any meaningful opportunity for an extended notice. He concludes nonetheless, that it is in AIU's best interest to give as much notice as practicable since the purpose is to notify transportation customers to modify their supply deliveries and/or gas consumption to help maintain system integrity.

AIU notes that CNE-Gas disagrees that 2 hours is sufficient and asserts that Nicor provides notification of a Critical Day at least 25 hours in advance and Peoples provides 23½ hours notice. CNE-Gas is perplexed as to why AIU can only provide 2 hours notice of an OFO and no commitment to advance notification for a Critical Day. To facilitate understanding of AIU's position, Mr. Glaeser proffers an example that demonstrates the concerns to committing to more than the 2-hour notice for an OFO and no prior notice period for a Critical Day. The AmerenCIPS Metro-East system distributes natural gas to Alton, Illinois and adjacent areas. This captive system serves approximately 18,000 customers and is connected to one interstate pipeline – Mississippi River Transmission Corporation – through the Federal Station and Chessen Lane Interconnections. The AmerenCIPS Metro-East system has no on-system storage. If the Federal Station interconnect facility experienced a pipeline rupture on a normal winter day, all 18,000 customers on the system would rapidly lose pressure within minutes. This would happen because Chessen Lane is a significantly smaller interconnect and can not supply the entire AmerenCIPS Metro-East system under normal winter load conditions. By issuing an immediate Critical Day and quickly implementing curtailment procedures, the system could be protected from a widespread outage by curtailing the largest customers before the entire system collapsed. The Chessen Lane station may be able to maintain system deliveries and pressure if the major industrial customers on the system shut down quickly. AIU argues that it is not practical to give any notice in this emergency situation to maintain system integrity – much less 24–hours' notice. AIU insists that it is, therefore, essential that it has the ability to issue a Critical Day without advance notice.

Of course, as stated in the tariff, AIU indicates that it will provide advance notification if possible, but providing advance notice may not be practical or even possible in certain situations. AIU asserts that the tariffs should reflect operational realities--and the reality is that advance notification can not always be given when a system emergency occurs. AIU maintains that CNE-Gas inaccurately compare AIU's notification period to Nicor and Peoples. Although all utilities could have ruptures on their systems, AIU contends that there may be differences in the resources available to recover from pipeline ruptures. AIU states that some utilities may have hub services readily available, while others may have fully integrated systems – unlike AIU, which has many isolated, captive systems (See Ameren Ex. 54.7, Ameren Illinois Natural Gas Facilities map). AIU speculates that even Nicor's or People's more integrated distribution systems or hub service resources could experience major failures leading to a more immediate crisis than the their tariff language implies. AIU reasons that the different resources available to respond to a system emergency may make the notification period different.

b. CNE-Gas' Position

When declaring an OFO or Critical Day, CNE-Gas argues that the Commission should require AIU to provide reasonable notice. CNE-Gas does not agree that 2 hours notice for OFOs is sufficient and contends that no notice for Critical Days is unacceptable. Certainly if force majeure conditions occur, CNE-Gas acknowledges that the standard notice intervals may require suspension due to extreme circumstances. However, under other OFO and Critical Day circumstances, CNE-Gas argues that transportation customers and their suppliers should receive adequate notification before such a ―non-force majeure" event is declared by an LDC. CNE-Gas contends that transportation customers deserve some degree of commitment from a utility that it will attempt to notify them in advance when these conditions occur so the transporter is able to take appropriate action to mitigate potential costs which may be incurred as a result of a Critical Day or OFO. CNE-Gas asserts that the rationale AIU offers for its inability to provide any Critical Day notice is no different than conditions that confront other utilities that offer notice. As discussed above, CNE-Gas observes that other Illinois utilities provide notice more than twenty hours in advance. CNE-Gas recommends that the Commission require AIU to provide OFO and Critical Day notice to customers that is comparable to the terms provided by other Illinois utilities.

c. Commission Conclusion

The Commission agrees with CNE-Gas that when comparing the notice provided by Nicor and Peoples and the notice that AIU proposes to provide, a great disparity seems to exist. A review of Ameren Ex. 54.7, however, appears to explain at least in part why AIU may not be able provide much notice in some isolated areas of its gas distribution systems. Clearly, there are multiple communities served by AIU which are connected to only one interstate gas pipeline. Under such circumstances, the unexpected loss of supply from the interstate pipeline could endanger system integrity so quickly that the amount of notice that CNE-Gas appears to be contemplating would not be feasible.

Other portions of AIU's distribution systems, however, may be well suited to the provisioning of additional notice by AIU before declaring an OFO or Critical Day. Such areas include where storage resources exist and/or there are multiple interconnections with interstate pipelines. While accepting AIU's OFO and Critical Day notice provisions for purposes of this proceeding, the Commission directs AIU to provide in its next gas rate case filing an analysis of its distribution systems identifying those areas that would not be immediately affected by a single event on the associated interstate pipeline(s). The analysis must also address with specifics whether AIU could provide notice in such areas comparable to the notice provided by Nicor and Peoples.

One other area of concern regards AIU's proposed Critical Day definition in Rider T. The fifth condition that may trigger a Critical Day under Rider T is "other market conditions which may warrant such action by the Company." Exactly what "market conditions" may warrant declaration of a Critical Day is unclear to the Commission. The tariffs of Nicor and Peoples do not appear to share this language. The Commission advises AIU to be cautious in the declaration of Critical Days for market reasons at least until it provides clarification in its next gas rate cases. In any event, the Commission expects AIU to only implement OFOs and Critical Days as last resorts in protecting system integrity.

15. AmerenCIPS and AmerenCIPS Metro-East Rate Areas

Currently, AmerenCIPS has two rate areas, AmerenCIPS and AmerenCIPS Metro-East. In its direct filing, AIU witness Warwick proposed to establish one set of gas tariffs for the entire AmerenCIPS footprint instead of the two current rate areas. Staff witness Harden objects to consolidating these service areas due to the unequal bill impacts for individual gas customers that could result from this change. Mr. Warwick later stated a willingness to accept the Staff position. He notes, however, that the rate conformance would bring about a rate reduction for certain customers under AIU's proposed rates and rate design. While AmerenCIPS agrees to forego rate consolidation at this time, AIU plans to raise the issue again in AmerenCIPS' next gas rate case consistent with Ms. Harden's comments.

The Commission acknowledges AIU's acceptance of Staff's position on this issue, but is nevertheless reluctant to adopt it in light of observations made by AIU in its Brief on Exceptions. AIU does not mean to suggest in its Brief on Exceptions that it is changing its position following its acquiescence to Ms. Harden's concerns, but simply wants to make the Commission aware of the impact on GDS-1 and GDS-2 customers in the AmerenCIPS and AmerenCIPS Metro-East rate areas if the customer charge is to reflect 80% of fixed costs. Using its August 22, 2008, supplemental response to the Administrative Law Judges' post-record data request, AIU explains that the monthly customer charge for GDS-1 AmerenCIPS customers would be $18.03, while the corresponding charge for AmerenCIPS Metro-East customers would be $22.01. If these rate areas are combined, AIU reports that the single GDS-1 monthly customer charge would be $18.43. AIU states further that the monthly customer charge for GDS-2 customers of AmerenCIPS would be $28.10 while that of AmerenCIPS Metro-East would be $56.71. Under a combined rate area, AIU states that the single GDS-2 monthly customer charge would be $29.97.

Even though these charges are somewhat different from those approved in this Order, the Commission is of the opinion that such disparities (particularly for GDS-2 customers) should be avoided when the means to do so is so readily available. Accordingly, for the purpose of the monthly gas customer charge, the AmerenCIPS and AmerenCIPS Metro-East rate areas should be combined for the GDS-1 and GDS-2 rate classes. The fact that these rate areas are to be eventually combined anyway further supports this conclusion.

E. Contested Electric Issues

1. Rate Limiter

a. AIU's Position

AIU recommends that the rate limiters implemented as part of the rate redesign case, Docket No. 07-0165, be modified or eliminated. AIU says that as a result of the rate redesign case, rate limiter provisions were added to DS-3 and DS-4. The total monthly charge for Distribution Delivery and Transformation Charges was limited to no more than 2¢/kWh where 20% or less of the customer's annual usage occurs in the summer months of June through September. The Distribution Delivery Charges for DS-3 and DS-4 were also increased, to maintain revenue neutrality. AIU indicates that Staff and GFA want to maintain the DS-4 rate limiter. AIU complains that neither GFA nor Staff offers an analysis of how much longer these limiters should persist.

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. According to AIU, the Commission expected that the parties would, in the instant rate case, be evaluating the period of time the rate limiter needs to be in place to ensure just and reasonable rates.

AIU has proposed moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU asserts that the GFA essentially asks to retain rate design concessions that, when combined with the move to on-peak demand determinates, would establish benefits for GFA constituents above and beyond those awarded in Docket No. 07-0165. AIU believes eliminating the DS-4 rate limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU contends that implementation of a rate limiter requires that Distribution Delivery Charges be increased for DS-3 and DS-4 customers. In other words, AIU says Distribution Delivery Charges are higher than they otherwise would be if there was no rate limiter. AIU claims that customers who do not benefit from the rate limiter subsidize customers who receive a benefit. AIU says eliminating the DS-4 rate limiter eliminates this inequity.

According to AIU, IIEC points out that there is no particular distinction for the customer group GFA singles out that warrants a long-standing subsidy. AIU indicates that the Commercial Group offers three reasons for eliminating the rate limiter. The Commercial Group claims that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment; rather it puts all customers within that class on a more equal footing with respect to rates being based on the true cost to serve. The Commercial Group also asserts that in Docket No. 07-0165 the Commission made it clear that the rate limiter is a transitional mechanism for certain customers who were facing large rate increases and that it should only be in place as long as necessary. The Commercial Group also contends that use of on-peak demand provides an incentive for rate limiter customers to reduce on-peak demands and potentially reduce their bills.

In AIU's view, the move toward on-peak demand determinates should be considered in evaluating the continued need for a DS-4 limiter. AIU proposes to begin using a billing demand applicable to the Distribution Delivery Charge equal to the higher of (a) the maximum on-peak demand in the month and (b) 50% of the highest off-peak demand in the month. Presently, the Distribution Delivery Charge is assessed based on a customer‘s monthly maximum demand (e.g., highest demand occurring in the billing month regardless of when it occurs). AIU says the aggregate impact of the proposed on-peak demand method is slight: proposed billing demands are slightly lower than present billing demands, where present demands are based on a customer‘s maximum demand regardless of when it occurs during the billing month. AIU states that for AmerenIP, AmerenCIPS, and AmerenCILCO, proposed billing demands are 97.8%, 96.3%, and 94.2%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands are 98.2%, 96.7%, and 98.4% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively. AIU claims that if only the on-peak demand is used, and the floor amount of 50% of the customer‘s off-peak demand ignored, the impact would be very small. For AmerenIP, AmerenCIPS, and AmerenCILCO, AIU says the proposed billing demands would be 97.7%, 95.5%, and 92.6%, respectively, of present billing demands for DS-3. For DS-4, proposed billing demands would be 98.2%, 96.0%, and 98.2% of present billing demands for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively.

AIU argues that changing to an on-peak demand method empowers rate limiter customers to shift demands to the off-peak period and thus reduce the demand charge component of their bills. AIU believes that retaining the rate limiter mitigates the price signal for customers subject to the rate limit to shift to the off-peak period. AIU states that while Staff is correct that there are potential benefits to both customers and AIU by encouraging customers to shift use toward the off-peak period, the change to billing demand will be most effective without a rate limiter in place.

AIU says the change to an on-peak demand method was actually advocated by IIEC in the previous delivery services cases and the Commission adopted IIEC‘s recommendation requiring AIU to provide data to allow a rate impact comparison between the existing methods and the on-peak method in the next delivery services case. AIU says that while it acknowledges the support Mr. Lazare and Mr. Adkisson provide for this change to an on-peak method, AIU believes this support undermines their position regarding the DS-4 rate limiter. AIU says a common theme in Staff's and the GFA's position is the perceived disproportionate impact that a segment of customers would face.

AIU indicates that GFA further argues for seasonal rate differentiation. Mr. Adkisson states there is not sufficient evidence for the Commission to determine the appropriateness of and level of a seasonal differential in delivery rates based on examining the 12 grain drying customers; however AIU believes this is only partially accurate. AIU agrees with Mr. Adkisson that there is insufficient evidence to set the level of a seasonal differential in delivery rates; however, AIU claims there is sufficient evidence to suggest that a majority of the 12 DS-4 grain-drying customers should pay a premium for primary voltage facilities. AIU says all DS-4 rate limiter grain drying customers are served from a primary supply line voltage (less than 15 kilovolt).

AIU states that all DS-4 customers have peak demands over 1,000 kW. According to AIU, these customers' demands are often large enough relative to all other customers on the circuit to drive the coincident peak to the fall grain drying season. AIU asserts that seasonal rate would not provide a lower price for these customers. AIU says an examination of circuits serving smaller (DS-3) customers eligible for the rate limiter has not yet been conducted. Until such analysis has been conducted, AIU claims it is unknown if demands contributed by DS-3 grain drying customers cause the circuit to peak in the fall. As a result, AIU suggests increasing the DS-3 rate limiter by an amount equal to the class average rate increase. AIU believes, however, that there is sufficient evidence in the record that the rate limiter affording to certain DS-4 customers should be eliminated.

AIU states that the Distribution Delivery Charge is based on a monthly demand and if a customer does not establish a demand during the monthly billing period, it will not pay a Distribution Delivery Charge in the month. AIU adds most grain drying customers set relatively large demands in 2 or 3 fall billing periods, and small demands in the remaining 9 or 10 billing periods. Thus, AIU says these grain drying DS-4 customers pay relatively small amounts of revenue in 9 or 10 billing periods and larger amounts in 2 or 3 monthly billing periods. According to AIU, most other DS-4 customers have relatively consistent usage, and thus a consistent revenue pattern, throughout the year.

AIU states that of the 12 grain drying rate limiter customers considered in this proceeding, 8 are served from a circuit and/or substation transformer with a fall peak, 2 customers are served from circuits and/or substation transformers that show equivalent peaks in both the summer and the fall, and 2 customers are served from the same substation with a peak occurring in the summer. AIU contends that customers or groups of customers contributing to the peak placed on distribution facilities, such as many of these grain dryers, should pay more of the cost for the system.

According to AIU, a review of the circuits serving DS-4 grain drying customers eligible for the rate limiter shows that the peak for those circuits is driven predominantly by customer demands occurring in the fall. In AIU's view, the rate limiter provides a subsidy to these seasonal customers at the expense of other DS-4 customers. AIU states that, assuming a DS-4 limiter of 2.82¢/kWh, 2.31¢/kWh, and 2.17¢/kWh, for AmerenIP, AmerenCIPS, and AmerenCILCO, respectively, grain drying customers would experience a benefit equivalent to just under 0.45¢/kWh. AIU adds that, assuming an average price per kWh paid of 9¢/kWh, the rate limiter would reduce the overall energy costs for a grain drying customer by about 5%.

AIU contends that DS-4 rate limiter customers drive the peak and costs on most distribution circuits, yet pay a relatively small amount toward those costs compared to non-grain drying customers. If the Commission finds the DS-4 limiter is still appropriate, but would like to begin the process of reducing reliance on the subsidy and set the rate at 3¢/kWh as AIU originally proposed for DS-3, AIU claims rate limitation reductions to class revenue would need to be reflected in AIU's proposed jurisdictional operating revenue. AIU says these values are provided in the third table on Ameren Ex. 26.1. AIU indicates that if the Commission instead chooses to simply increase the existing 2¢/kWh rate limiter by the average DS-4 rate increase for each AIU, the corresponding limited revenue amount are also shown within the third table of Ameren Ex. 26.1.

b. GFA's Position

GFA claims that its members suffered rate shock when the rates imposed in 2006 were implemented. Commission approval of the DS-3 and DS-4 rate limiters, however, helped to mitigate the impact of triple digit percentage rate increases for grain dryers and seasonal use customers. GFA says that customers that limit their total kWh usage during the four summer billing periods of June through September to 20% or less of their annual kWh consumption qualify and may be eligible for the rate limiter. The rate limiter is calculated each billing period for qualifying customers by adding the individual customer‘s monthly Distribution Delivery Charge and Transformation Charge revenues and dividing the sum by the customer‘s total kWh for that billing period. GFA states that if the combined charge is greater than 2¢/kWh, a credit for the amount over 2¢/kWh will be applied to the customer‘s bill. GFA indicates that the rate limiter limits the average monthly cost of the Distribution Delivery Charge and the Transformation Charge to 2¢/kWh, which is several times higher than the previous and current class average ¢/kWh, but can be less than what an individual customer would have otherwise paid. GFA notes that the rate limiter is not applicable to Customer, Meter, Transmission, Reactive or Power and Energy charges.

GFA indicates that the DS-3 and DS-4 tariffs with the rate limiter became effective October 19, 2007 and less than three weeks later, on November 2, 2007, AIU filed these rate cases. GFA says that AIU proposes to totally eliminate the DS-4 rate limiter, which would allow an unlimited increase for DS-4 customers and initially proposed a 50% increase to the DS-3 rate limiter, from 2¢/kWh to 3¢/kWh. GFA states that in its rebuttal testimony, AIU agrees to support an increase to the DS-3 rate limiter equal to the class average increase. For the purpose of this rate case, GFA indicates it will no longer object to such an increase; however, GFA continues to oppose the proposal to eliminate the DS-4 rate limiter. In GFA's view, it is simply too soon to eliminate the rate limiter.

GFA states that AIU has recommended across-the-board increases on its rates, with the exception of the rate limiter. GFA contends that AIU‘s proposal is unfair and would effectively undo the Commission‘s Order in Docket No. 07-0165. According to GFA, if the Commission raises AIU‘s rates across the board, then the rate limiter should receive that same treatment.

GFA says that if, in the next rate case, AIU bases its proposed rates on a class COSS, then the Commission will have the opportunity to review and reconsider all aspects of rate design, including the rate limiters. Additionally, GFA suggests that all parties will be able to voice their respective concerns and opinions regarding the rate limiters, seasonal rates, and other rate design features. GFA asserts that if the rate limiter is to be modified or eliminated, it should be done in conjunction with a COSS, where all factors can be considered.

In its Reply Brief, GFA says it has not ignored the Commission's direction in Docket No. 07-0165, and says it has performed the evaluation requested by the Commission. GFA claims that for a number of reasons, it and Staff determined that the most reasonable course of action is for the Commission to apply to the rate limiter the same across-the-board increases that are being applied to other rate components. While the Commission stated its desire to have the parties reevaluate the rate limiter, GFA argues there is nothing in its Order indicating its knowledge that AIU would file a rate case less than three weeks after implementation of the rate limiter, seeking to eliminate the rate limiter. GFA also says nothing in the Order indicates that the Commission anticipated an across-the-board increase rather than a full review of a class COSS and cost-based rate design.

AIU argues that its proposal to move to an on-peak determinant for establishing demand rates obviates the need for the rate limiter. GFA states that even if DS-4 customers were able to shift on-peak load to off-peak period and totally capture the prospective benefits of the proposed change in billing demand determination, the resulting benefits pale in comparison to the triple digit increases grain dryers will experience without the DS-4 rate limiter.

GFA proposes seasonal delivery rates while AIU argues against seasonal rates. According to GFA, AIU ultimately, takes the position that a proposal to implement seasonal delivery rates is not appropriate at this time and requires further analysis. GFA agrees that further analysis should take place, therefore, it recommends that the Commission order AIU to begin collecting data necessary for determining seasonal delivery rates and to provide those data to the Commission and other parties prior to filing its next electric rate case.

c. Staff's Position

Staff says that while AIU generally accepts the across-the-board approach to increasing existing rates, AIU continues to recommend that the rate limiter for the DS-4 class be eliminated. AIU argues that the peak for these customers is driven by demands during the fall season which suggests that customers under the rate limiter are being subsidized by others within the class. AIU also suggests the limiter would not have a significant effect on grain drying customers, reducing their overall energy costs by about 5%. AIU also presents the option of setting the limiter for DS-4 customers at 3¢/kWh as it originally proposed for DS-3.

Staff says that since it and AIU agree that bill impacts are the preeminent concern, it does not make sense to base rates for the large majority of customers on bill impacts while setting rates for a small number of customers receiving the rate limiter according to costs. Staff asserts that those latter customers can rightly complain of being held to one standard for ratemaking when other customers are held to another standard. In Staff's view, the only reasonable approach in this difficult ratemaking environment is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes.

d. IIEC's Position

IIEC takes no position on the extension of the rate limiter for DS-3 customers; however, it opposes the extension for DS-4 customers. IIEC states that grain dryers and seasonal use customers are not the only customer classes that experienced large increases in delivery service rates. According to IIEC, some DS-4 customers other than grain dryers or seasonal use customers experienced rate increases of over 200% in AIU's last delivery service case. IIEC says other customer classes also experienced significant rate increases in going from the 2006 rates to the 2007 rates. In IIEC's view, there is no basis for a continued distinction between these customers and the customer group represented by GFA, especially where it establishes a continuing subsidy. IIEC asserts that GFA has not demonstrated why these particular DS-4 customers should be entitled to the continuing benefits of the rate limiter while other DS-4 customers do not enjoy rate mitigation.

GFA argues that the rate limiter has not been in effect long enough and points out that AIU filed this rate case three weeks after the rate limiter took effect. According to IIEC, GFA ignores the fact that the rate limiter for DS-4 grain drying customers will have been in place for almost one year by the time the rates approved in this case take effect. IIEC believes that under such circumstances, there is no justification for continuation of the rate limiter for DS-4 grain drying customers. In response to GFA's suggestion that the rate limiter should only be eliminated in conjunction with a COSS, IIEC points out that a COSS is available in this proceeding.

IIEC notes that Staff has concluded that elimination of the rate limiter would result in grain drying customers, such as the DS-4 grain drying customers, being held to one standard for ratemaking when other customers are held to another standard. IIEC argues that Staff has it exactly backwards. According to IIEC, the rate limiter for DS-4 customers, who happen to be grain dryers, does result in one standard being applied to those customers while another standard is applied to other DS-4 customers who have also experienced rate shock, but who do not benefit from the rate limiter.

e. Commercial Group's Position

According to the Commercial Group, given that the rate limiter subsidies must be collected only from DS-3 and DS-4 customers, phasing out the rate limiter would relieve the stresses on the DS-3 and DS-4 customers who are required to provide both intra-class subsidies to the customers taking advantage of the rate limiter and interclass subsidies to other classes. The Commercial Group believes this is an unfair burden that should be eliminated.

The Commercial Group disagrees with Staff that elimination of the rate limiter is inconsistent ratemaking that singles out one group of customers for unequal treatment. The Commercial Group argues that eliminating a rate provision that created intra-class subsidies does not result in unequal treatment. In the Commercial Group's view, it puts all customers within that rate class on a more equal footing with respect to their rates being based on the true cost to serve. The Commercial Group insists that it is unequal for certain customers in a class to subsidize other customers in the class, particularly where the subsidized customers' rates are already below cost before the rate limiter is applied. The Commercial Group believes the rate limiter has served its limited transitional purpose and should be eliminated. If it is not completely eliminated in this case, the Commercial Group submits that the rate limiter should be phased out and eliminated as AIU proposed in its direct testimony.

The Commercial Group agrees with AIU and IIEC that the DS-4 rate limiter should be eliminated. The Commercial Group also urges the Commission to eliminate the DS-3 rate limiter. According to the Commercial Group, there is even more reason to do so, because DS-3 rates for AIU are already significantly above cost. The Commercial Group submits that with the rates of grain customers being below cost even before the rate limiter is applied, the rest of the DS-3 class is subsidizing not only other rate classes, but other ratepayers within the class. The Commercial Group claims that this double subsidy stresses DS-3 customers who are concerned with the impact of increasing electric bills on operations at schools, retail facilities, and industrial facilities.

f. Commission Conclusion

AIU proposes that the rate limiter provision for DS-3 be increased proportionate to the average rate-increase for that class, and that the provision for DS-4 be eliminated. AIU says that in Docket No. 07-0165, the Commission ordered that the rate limiter should be in place only as long as necessary. AIU also proposes moving to an on-peak determinate for establishing demand rates and claims there is no opposition to this proposal. AIU believes eliminating the DS-4 Rate Limiter would inject fairness by moving rates closer to cost and avoiding the unnecessary subsidization inherent in such limiters. AIU adds that customers who do not benefit from the rate limiter subsidize customers who receive a benefit.

For purposes of this proceeding, GFA does not oppose an increase to the DS-3 rate limiter equal to the class average increase. GFA continues to oppose the proposal to eliminate the DS-4 rate limiter because it believes it is too soon to eliminate that benefit. In Staff's view, the only reasonable approach is to apply a consistent across-the-board approach to all existing rate elements, including the existing rate limiters for the DS-3 and DS-4 classes. IIEC takes no position on the extension of the limiter in this case for DS-3 customers; however, IIEC opposes the extension of the rate limiter for DS-4 customers. The Commercial Group advocates eliminating the rate limiter for both DS-3 and DS-4 classes.

As the parties are well aware, the Commission generally favors rates that reflect the cost of service. The Commission, however, is keenly aware that its rate decisions can have adverse impacts on some customers if extreme care is not exercised. The Commission is especially intent on avoiding the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if Staff's proposal to apply an across-the-board increase to the existing rate limiters for both DS-3 and DS-4 classes is adopted. The Commission is committed to eliminating these rate limiters at the earliest opportunity; however, the Commission concludes that the time to do so has not yet arrived.

2. Street Lighting

a. AIU's Position

AIU states that it and LGI concur on certain municipal street-lighting issues. AIU says it provided a detailed COSS, contained in Schedule E-6, for the current rate cases and will provide a similar COSS in the next set of rate cases, along with the requested lighting rate design study aimed at determining cost-based lighting fixture charges. With regard to LGI's street light fixture rate proposal, AIU disagrees with LGI's proposed approach.

For the purpose of this case, LGI recommends capping AmerenIP street light fixture rates, and that the resulting reductions to AmerenIP's filed revenue requirement related to street lighting be passed along to all delivery service customer classes. AIU notes that LGI only represents municipalities within the AmerenIP service territory.

AIU provides the following tables to demonstrate the street lighting proposals advanced by the AIU and LGI:

Average Cost per Month per Fixture

		AIU Proposal		LGI Proposal	
Municipality	Existing Rates	Monthly Price	Change	Incremental Change	Monthly Price
Champaign	$ 8.66	$ 12.64	$ 3.98	$ 1.29	$ 9.95
Bloomington	$ 8.03	$ 11.72	$ 3.69	$ 1.20	$ 9.23
Normal	$ 8.07	$ 11.78	$ 3.71	$ 1.20	$ 9.27
Urbana	$ 8.50	$ 12.33	$ 3.83	$ 1.17	$ 9.67
Decatur	$ 7.81	$ 11.40	$ 3.59	$ 1.16	$ 8.97

Per Capita Average Cost per Month

Municipality	Existing Rates	AIU Proposal Monthly Price	AIU Proposal Change	LGI Proposal Incremental Change	LGI Proposal Monthly Price
Champaign	$ 0.17	$ 0.24	$ 0.07	$ 0.02	$0.19
Bloomington	$ 0.49	$ 0.71	$ 0.22	$ 0.07	$0.56
Normal	$ 0.36	$ 0.52	$ 0.16	$ 0.05	$0.41
Urbana	$ -	$ -	$ -	$ -	$ -
Decatur	$ 0.86	$ 1.26	$ 0.40	$ 0.13	$0.99

According to AIU, LGI witness Hughes proposes to cap the fixture rates increase in the AmerenIP service territory by no higher than 14.89%. AIU states that the proposed DS-5 class provides customers with dusk-to-dawn photo cell-controlled lighting service. AIU adds that while it will typically own and maintain the lighting fixture, DS-5 will provide for customers who own their own lighting facilities as well.

AIU indicates that LGI only addresses the charges for fixtures. AIU indicates that the fixture charges in DS-5 do not cover power and energy charges, transmission charges, or delivery-service charges. To achieve the targeted revenue requirement for each class, AIU proposed fixture charges laid out in Ameren Ex. 12.7E. AIU proposes to adjust those charges on an equal percentage basis unique to each utility. AIU states that transmission and energy charges are charged separately through Rider TS and Rider BGS, and distribution delivery charges are assessed through a separate component within DS-5.

According to AIU, Ms. Hughes proposes that AmerenIP's fixture charges be capped based on the incremental costs of fixtures calculated several years ago for use in Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and recommends funding this cap by shifting costs to other rate classes. In AIU's view, Ms. Hughes' case for carving out an exception to the across-the-board increase is not persuasive. AIU complains that Ms. Hughes does not clarify why AIU's DS-5 class, and that class alone, should be allowed use of a non-across-the-board revenue allocation method, while other classes are held to an across-the-board approach. AIU also says that Ms. Hughes fails to extend the concept of incremental-cost pricing to AmerenCIPS and AmerenCILCO. AIU argues that LGI customers have the option of choosing to purchase their own street lighting fixture and avoid AmerenIP's fixture rates all together, while other delivery service customers have no service choice. AIU insists that it is unfair to shift an amount potentially in excess of $5 million dollars from charges that certain customers pay by choice to other customers, including residential customers.

In its Reply Brief, AIU says it does not think it is appropriate to shift revenues between classes in a manner that would disturb the intended purpose of the rate redesign docket. In particular, AIU claims it would not be appropriate to shift revenue recovery between classes in a manner that creates impacts for residential and small business customers. AIU argues that the revenue impacts associated with a realignment of rates to more closely match class cost of service indicators would result in impacts to residential customers. AIU objects to such a realignment of rates at this time.

AIU acknowledges the disparity between street light fixture rates in each service territory; however, AIU says it is unclear what authority or legal basis the Commission would have to shift revenue responsibility between separate legal entities. AIU says that while the rate proceedings in this matter are consolidated, the operating utility entities that make up AIU are not. AIU argues that in future rate proceedings, the more appropriate approach to bring uniformity would likely be a rate design that moves rates toward class cost of service indicators, to the extent feasible.

b. LGI's Position

LGI claims that the street lighting fixture charge is unique in this docket because it is not a delivery service; rather it is a payment for a tangible piece of hardware and the labor involved in maintaining that hardware. LGI indicates that the delivery service charge for street lights is totally separate and apart from the street light fixture. LGI says in an over-simplified example, the fixture charge covers the cost of the arm and bulb and how many persons it takes to change the light bulb on the street light. According to LGI, because of its unique nature, there is no reason why the Commission can not separately set the rate for the street lighting fixture charge based on the cost of service as AIU did for the meter and customer charge, rather than on an across-the-board basis.

LGI states that the fixture charges vary greatly for the three electric utilities. Initially, LGI proposed that the Commission unify the fixture charges in this proceeding. LGI believes that the move to common lighting offerings across the footprint is a step toward easing customer understanding of AIU lighting offerings and streamlining operations. LGI says this standardization already occurred for Meter and Customer Charges, which are now all identical for the three utilities. LGI argues that the result of applying the across-the-board increase to street light fixtures would be to move the fixture charges further apart, making a standardized offering more difficult in the future.

LGI contends that it takes the same number of persons to change a light bulb for AmerenIP as it does for AmerenCILCO and AmerenCIPS; yet, using an across-the-board increase, the rates charged for street lighting fixtures will increase by 9.5% for AmerenCILCO, 19.2% for AmerenCIPS, and 46.0% for AmerenIP. LGI states that for AmerenCIPS the current street light fixture charge for a 100-Watt light fixture is $3.12 per month, for AmerenCILCO the charge is $7.13, and for AmerenIP, the charge is $7.59. LGI says under AIU's proposed across-the-board increase, these rates would increase to $3.72 for AmerenCIPS, $7.81 for AmerenCILCO, and $11.08 for AmerenIP. LGI suggests the cost of a light bulb and the cost to replace the light bulb is not nearly three times the amount for AmerenIP compared to AmerenCIPS.

LGI believes that eventually the street light fixture charge should be uniform throughout AIU's service areas; however, in its rebuttal testimony LGI focuses only on AmerenIP. Using AmerenIP's 2006 embedded COSS and the lighting specific incremental cost study performed in the last case, Ms. Hughes recommends that the increase to AmerenIP's lighting fixture rates be limited so that the fixture rates are set equal to the common incremental cost for each fixture type and size. LGI says using the incremental cost, the AmerenIP fixture charges still will be higher than the cost for AmerenCIPS and AmerenCILCO. For example, LGI indicates that the incremental cost for a 100 watt high pressure sodium vapor fixture for AmerenIP is $8.72, while the proposed rate for the same fixture for AmerenCIPS is $3.72 and for AmerenCILCO is $7.81. LGI states that under its current proposal, AmerenIP customers would still pay more for fixture charges than municipalities taking service from either AmerenCIPS or AmerenCILCO but the disparity would be lower than if the fixture charges were increased using AIU's proposed across the board increase. LGI proposes that the Class B pole charge also be set equal to the incremental cost for AmerenIP. Under LGI's proposal, the revenue reduction resulting from the decrease in fixture and pole charges from the proposal by AmerenIP would be allocated to the other DS customer classes using an equal percentage increase in the DS delivery charge.

LGI claims the result of its proposal is that the street lighting fixture charge for AmerenIP customers would increase by 14.89%. LGI says the effect on other customers would increase the across-the-board increase for the DS-1 through DS-4 delivery service charge from 41.14% to 42.58%. Under LGI's proposal, the DS-5 delivery service charge rate also would increase by the same percentage (42.58%). LGI states that taking into account both the recommended fixture charge and the increase to the DS-5 delivery charge, the overall increase to the DS-5 Lighting Class is 21.37%.

LGI argues that this total lower percentage increase for the DS-5 lighting class is supported by AIU's own embedded COSS. LGI claims this study indicates that the DS-5 Lighting Class contributes a higher return on rate base at existing rates than all other DS rate classes, except for the DS-2 class. LGI asserts that applying an equal across-the-board percentage increase to all rate classes maintains or amplifies the existing disparity that DS-5 lighting rates will continue contributing higher returns relative to other rate classes.

According to LGI, AIU's opposition appears to be rooted in the fact that since it is recommending an across-the-board increase for all other classes, it believes that there should be no exception for the fixture charge. In LGI's view, AIU misses the point that the fixture charge is not a traditional delivery service charge. LGI says the delivery service charge portion of the DS-5 rate remains subject to the across-the-board increase. LGI recommends that only the light bulb, fixtures, and light bulb changing be separated from the across-the-board increase as was done with the Meter and Customer Charges that are now uniform for AmerenCILCO, AmerenCIPS, and AmerenIP.

LGI says it made three additional recommendations, all of which were accepted by AIU. LGI recommends that AIU be required to file a detailed COSS in its next rate case showing the allocation of costs between the delivery service customer classes, including a company-wide lighting cost of service analysis for AIU to identify lighting fixture costs. LGI recommends that AIU be required to file a detailed streetlight rate design study to determine cost-based lighting fixture charges. LGI recommends that any reductions to AIU's filed revenue requirement resulting from the Commission‘s decision should be passed along to all DS customer classes, including the DS-5 Lighting Class, in the form of a lower across-the-board percentage rate increase. LGI suggests that these recommendations should be included in the final order in this proceeding.

According to LGI, AIU attempts to confuse the issue by showing the per capita average cost per month for the fixture charge. LGI claims this is a meaningless comparison because rates are not set on a per capita basis. LGI says AIU simply takes the monthly charge for municipal lighting fixtures by municipality divided by the population of the municipality. LGI complains that AIU does not explain why this is a meaningful exercise and, if it is so meaningful, why it does not determine all of its rates on a per capita basis. LGI asserts that AIU can not hide the fact that if an across-the-board increase is granted for AmerenIP‘s municipal lighting fixture charge, the charge will be $11.08 compared with only $3.72 for AmerenCIPS and $7.81 for Ameren CILCO.

In response to AIU's statement that LGI customers can avoid the charge by buying their own arms and bulbs if they do not like the rate, LGI claims AIU apparently wants to make the fixture charge so unreasonable that municipalities will install their own arms and bulbs rather than pay for AmerenIP‘s. LGI argues that while taking down AmerenIP‘s arms and bulbs and replacing them with municipality-owned arms and bulbs may be a long-term solution, changing out all arms and bulbs on street lights is neither an immediate nor a practical solution. Instead, LGI contends the reasonable and practical solution is for the Commission to set the municipal street lighting fixture charge based on the incremental cost.

c. Commission Conclusion

AIU proposes to increase street lighting rates, including its charges for fixtures, on an across-the-board basis. LGI objects to increasing fixture charges in AmerenIP's service area in the manner AIU proposes. LGI recommends that the Commission limit fixture charges to the incremental cost of those fixtures. AIU does not believe there is sufficient reason to deviate from its across-the-board rate increase proposal for light fixture charges. Also, AIU expresses concern about shifting revenue recovery between classes in a manner that creates impacts for residential and small business customers.

It appears to the Commission that LGI has raised a legitimate concern. In the Commission's view, ultimately, it will in all likelihood be difficult for AIU to justify light fixture charges that are as different as they currently are between AmerenCILCO, AmerenCIPS, and AmerenIP. But as previously discussed, the Commission is aware that its rate decisions can have adverse impact on some customers if extreme care is not exercised. The Commission wishes to avoid the type of situation that led to the recent AIU rate redesign proceeding, Docket No. 07-0165. Given the circumstances and facts present here, the Commission believes that the best outcome will result if it adopts AIU's proposal to increase light fixture charges on an across-the-board basis. The Commission directs AIU, in its next electric rate case to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP.

3. Allocation of Costs to Subclasses

As discussed elsewhere in this Order, the Commercial Group opposes using an across-the-board approach to increase electric rates, favoring the use of AIU's COSS as the basis for any increase. In the event the Commission accepts the Commercial Group's recommendation on this point, the Commercial Group is concerned about the application to subclasses.

The Commercial Group argues that with respect to the DS-3 and DS-4 subclasses, the COSS do not accurately match cost to revenues on the subclass level and therefore are not reliable for differentiating subclass revenue levels. The Commercial Group states that the AmerenCILCO cost study shows the DS-4 secondary subclass as requiring a 3,729% increase. The Commercial Group claims that AIU assigned 100% of line transformer cost ($15.1 million) for the DS-4 class to the DS-4 secondary subclass but, none of the corresponding $2.6 million in transformation revenues that AIU received from the class. The Commercial Groups says that instead, only $53,000 in revenue, consisting entirely of meter charge and customer charge revenue was allocated to DS-4 secondary. The Commercial Group contends that given that transformer cost but not the revenue produced from those transformers was allocated to DS-4 secondary, it is not surprising that the study would show that an enormous revenue increase would apparently be required for the DS-4 secondary. The Commercial Group concludes that AIU's COSS are generally reliable for class costs and revenues, but are not reliable at the subclass level.

While the Commission appreciates the Commercial Group's concern regarding the allocation of costs and revenue to DS-4 subclasses, as the Commission has chosen to not use AIU's COSS as the basis for setting rates in this proceeding, it does not appear that this issue need be addressed further in this Order.

4. Combining DS-3 and DS-4

a. Kroger's Position

Kroger states that the DS-3 rate class is comprised of nonresidential customers that have billing demands ranging from 150 kW up to 1,000 kW, while the DS-4 rate class is comprised of all nonresidential customers with billing demands of 1,000 kW or greater. Kroger adds that the Distribution Delivery Charge is a demand charge levied on a per-kW basis, with rates differentiated with respect to voltage level: primary, high voltage, and transmission voltage. Kroger says unlike other charges contained within the DS-3 and DS-4 rates, the Distribution Delivery Charge is not uniform between DS-3 and DS-4. According to Kroger, for each AIU utility, and at each voltage level, the proposed Distribution Delivery Charge is significantly higher for DS-3 than DS-4. Kroger proposes that the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules should be approximately equalized. Kroger argues that there is no significant cost of service difference between DS-3 and DS-4 customers at the same voltage level, yet AIU proposes that DS-3 customers pay a substantially higher Distribution Delivery Charge.

Kroger suggests that if providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW, then perhaps these customers should not be placed into different rate classes in the first instance. Kroger also claims it is not reasonable to charge the 150 kW customer a dramatically higher per-kW Distribution Delivery Charge than the 2,000 kW customer taking service at the same voltage. In Kroger's view, the lack of a uniform Distribution Delivery Charge for DS-3 and DS-4 will result in an anomalous rate transition that will cause a great inequity. Kroger asserts for example, if there are two AmerenCILCO primary voltage customers who are otherwise identical, but one places a 1,000 kW demand on the system (DS-4) and the other places a 600 kW demand on the system (DS-3), the 600 kW customer that places a significantly smaller strain on the system will pay a higher Distribution Delivery total bill than the 1,000 kW customer. Kroger suggests that AIU‘s proposed Distribution Delivery Charges would send the signal to DS-4 customers to not reduce energy consumption. Kroger believes this anomaly is particularly inappropriate given the Commission‘s interest in promoting energy efficiency.

Kroger complains that AIU ignored the Commission‘s Order in the previous rate case, and failed to address the issue of whether there is sufficient justification for separate DS-3 and DS-4 classes in this proceeding. Instead, Kroger says AIU has proposed an equal percent across-the-board delivery rate increase, which retains the relative disparities between DS-3 and DS-4 established in the last proceeding, and makes the absolute differences between the rate schedules even greater. Kroger asserts that the Commission ordered AIU in its previous distribution rate case filing (Docket Nos. 06-0070, 06-0071, and 06-0072 (Cons.)) to ―address [the appropriateness of maintaining separate DS-3 and DS-4 rates] in its next delivery services rate case filing." (Order at 175)

According to Kroger, AIU‘s COSS in this proceeding provide even more evidence that DS-3 and DS-4 rates should be converged. Using the information from AIU's Schedule E-6 filings, Kroger prepared the table below comparing the rates of return being provided by DS-3 and DS-4 customers.

AIU COSS Rates of Return

	Rates of Return			
Utility Distribution Company	Ill. Elec.	DS-3a	DS-3b	DS-4
AmerenIP	2.75%	3.40%	5.94%	4.44%
AmerenCIPS	4.72%	9.93%	8.83%	2.77%
Ameren CILCO	6.92%	12.22%	12.89%	5.31%

Kroger says AIU is generally over-recovering costs from DS-3 customers relative to DS-4. In Kroger's view, these results are not surprising in light of the disparity in the Distribution Delivery Charges between the two customer classes. Kroger asserts that the greater the disparity in the Distribution Delivery Charges, the greater the disparity in rates of return being produced by the two customer classes.

Kroger believes the artificial distinction between DS-3 and DS-4 customers should be eliminated in this proceeding and the DS-3 and DS-4 rates should be jointly determined. Kroger calculated uniform distribution delivery charges for DS-3 and DS-4, which it presented in Kroger Ex. 1.1 using AIU‘s requested revenue requirement. Kroger states that the only difference between the DS-3 and DS-4 Distribution Delivery Charges is the recognition of DS-4 reactive power revenues as a credit against the DS-4 Distribution Delivery Charge. If the Commission finds merit in this argument, but is reluctant to move to uniform DS-3 and DS-4 rates at this time, Kroger suggests that, in the alternative, the Commission initiate steps in this proceeding to move the DS-3 and DS-4 rate schedules closer together over time. Kroger suggests that this could be implemented by removing 50% of the differential between the rates at this time.

b. AIU's Position

Kroger argues that the DS-3 and DS-4 rate schedules should be approximately equalized, that is, there should be no cost of service difference between customers who are served at the same voltage level. According to AIU, Kroger claims that the issue of the relationship between the DS-3 and DS-4 rates was required to be addressed by AIU in this proceeding. AIU observes that no other party has made this claim. AIU says the Commission‘s Order states: ―When Ameren files its next delivery services rate case (assuming that filing is in 2009 or later), it should provide sufficient information for the Commission to either retain the current DS-3 classification or adopt the DS-3 classification within the subclasses proposed by Wal-Mart." (Docket Nos. 06-0070/06-0071/06-0072 (Cons.), Order at 156) AIU claims Kroger knew or should have known upon review of the direct filing, that the DS-3 and DS-4 rate consolidation analysis had not been performed.

In AIU's view, the Commission‘s decision to wait until 2009 to review this issue makes sense. AIU notes that these delivery service rates first came into effect on January 2, 2007 and AIU believes waiting for some period of time is appropriate, so that any analysis offered post-2009 would have sufficient data and information. AIU alleges that combining rates without the required analysis is a recipe for disaster. AIU contends that undue bill impacts, questionable price signals and revenue recovery concerns all remain unknown and unpredictable. AIU says the Distribution Delivery Charge recovers the remainder of the revenue requirement, and is currently set to recover the revenue requirement from DS-3 and DS-4 classes. AIU asserts that combining these rates at this time leaves too many unknowns, and is inappropriate at this time. AIU submits that further analysis of the DS-3 and DS-4 classes could lead to more rate differentiation rather than less.

c. IIEC's Position

IIEC suggests that in lieu of adopting Kroger's proposal to equalize distribution delivery service charges for DS-3 and DS-4, the Commission adopt a cost-based approach to revenue requirement allocation, which would lead to lower distribution and delivery service charges for DS-3 customers as well as DS-4 customers. IIEC generally agrees with the AIU position that DS-3 and DS-4 should not be equalized in this case, because there has not been sufficient cost analysis provided to justify the combination. Such a combination would result in lower charges for DS-3 customers and higher charge for DS-4 customers, according to IIEC. IIEC notes that Kroger's proposal is based on statements from prior delivery service rate cases that, on a conceptual basis, suggest the cost per kW of serving a customer of the same voltage level at 900 kW is not much different than the cost per kW of serving a similar customer at 1,100 kW of demand. IIEC observes that AIU witnesses point out that the cost of serving these customers may be similar, but the revenue from the customers may or may not be sufficient to recover their individual costs. According to IIEC, this suggests that rate changes not discussed in this record may be needed to implement the Kroger approach. IIEC also argues that the Commission directed that this issue be considered in a rate case filing in 2009 or later citing to Docket Nos. 06-0070, 07-0071, and 06-0072 (Cons.) (Order at 156).

IIEC argues further that Kroger's alternative proposal to equalize delivery distribution charges for DS-3 and DS-4 by removing 50% of any difference between the rates as they exist today does not mitigate AIU's concerns in terms of potential impacts and consequences of equalizing these rates at this time. Adoption of the AIU proposal would not, according to IIEC, reduce by 50% the magnitude of the problems associated with the Kroger proposal. IIEC adds that the impacts of moving towards equalization remain unknown and unpredictable based on the record in this case. IIEC, therefore, recommends that the proposal to combine DS-3 and DS-4 be rejected in this case.

d. Commission Conclusion

In AIU's last rate case, the Commission entertained not only arguments over the possibility of combing rates DS-3 and DS-4, but also the possibility of splitting rate DS-3 into subclasses. The Order in AIU's last rate case clearly contemplated reconsidering whether to split rate DS-3 into subclasses in 2009 or after. While the Order was not quite as clear with respect to when it would reconsider combining rates DS-3 and DS-4, the Commission does not believe combining rates DS-3 and DS-4 in this rate case and, possibly creating a new rate DS-3 in a subsequent rate case constitutes sound ratemaking policy. In fact, it seems to contradict the rate design principle commonly called rate continuity. Thus, while the Commission remains open to the possibility of restructuring rates DS-3 and DS-4 when sufficient information is available to fully analyze the implications of any restructuring, the Commission affirms its decision from Docket Nos. 06-0070/06-0071/06-0072 (Cons.) and directs AIU to address these two issues in its first electric rate cases filed in 2009 or thereafter.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) AmerenCILCO, AmerenCIPS, and AmerenIP are Illinois corporations engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and are public utilities as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendix A attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's electric operations; Appendix B attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' electric operations; Appendix C attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's electric operations; Appendix D attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's gas operations; Appendix E attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' gas operations; and Appendix F attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's gas operations;

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2006, as adjusted; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $240,625,000;

(6) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $443,743,000;

(7) for purposes of this proceeding, the net original cost rate base for AmerenIP's electric delivery service operations for the test year ending December 31, 2006, as adjusted, is $1,254,459,000;

(8) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $183,734,000;

(9) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $181,735,000;

(10) for purposes of this proceeding, the net original cost rate base for AmerenIP's gas delivery service operations for the test year ending December 31, 2006, as adjusted, is $518,857,000;

(11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.01%; this rate of return incorporates a return on common equity of 10.65%;

(12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.20%; this rate of return incorporates a return on common equity of 10.65%;

(13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.68%; this rate of return incorporates a return on common equity of 10.65%;

(14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 8.03%; this rate of return incorporates a return on common equity of 10.68%;

(15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 8.22%; this rate of return incorporates a return on common equity of 10.68%;

(16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.70%; this rate of return incorporates a return on common equity of 10.68%;

(17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of $115,827,000 and net

annual operating income of $19,273,000 based on the test year approved herein;

(18) the rate of return for AmerenCIPS set forth in Finding (12) results in base rate electric delivery service operating revenues of $218,466,000 and net annual operating income of $36,387,000 based on the test year approved herein;

(19) the rate of return for AmerenIP set forth in Finding (13) results in base rate electric delivery service operating revenues of $442,556,000 and net annual operating income of $108,887,000 based on the test year approved herein;

(20) the rate of return for AmerenCILCO set forth in Finding (14) results in base rate gas delivery service operating revenues of $71,308,000 and net annual operating income of $14,754,000 based on the test year approved herein;

(21) the rate of return for AmerenCIPS set forth in Finding (15) results in base rate gas delivery service operating revenues of $70,450,000 and net annual operating income of $14,938,000 based on the test year approved herein;

(22) the rate of return for AmerenIP set forth in Finding (16) results in base rate gas delivery service operating revenues of $167,424,000 and net annual operating income of $45,140,000 based on the test year approved herein;

(23) the electric delivery service rates as well as the gas delivery service rates of AmerenCIPS and AmerenIP which are presently in effect are insufficient to generate the operating income necessary to permit each company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(24) the electric and gas delivery service rates of AmerenCILCO which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base: these rates should be permanently canceled and annulled;

(25) the specific rates proposed by AmerenCILCO, AmerenCIPS, and AmerenIP in its respective initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates of each company should be permanently canceled and annulled consistent with the findings herein;

(26) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $115,827,000, which represents a decrease of $2,778,000 or (2.25%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(27) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $218,466,000, which represents an increase of $21,956,000 or 10.31%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (12) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(28) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $442,556,000, which represents an increase of $103,867,000 or 29.16%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (13) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(29) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $71,308,000, which represents a decrease of $9,234,000 or (11.19%); such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (14) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(30) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $70,450,000, which represents an increase of $7,659,000 or 11.74%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (15) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(31) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $167,424,000, which represents an increase of $39,792,000 or 30.01%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding

(16) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(32) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AmerenCILCO, AmerenCIPS, and AmerenIP should incorporate the rates and rate design set forth and referred to herein;

(33) new tariff sheets authorized to be filed by this Order should reflect an effective date not less than three days after the date of filing, with the tariff sheets to be corrected, if necessary, within that time period; and

(34) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for electric delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in electric delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on November 2, 2007, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (26), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (27), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (28), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (29), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (30), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (31), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 24th day of September, 2008.

(SIGNED) CHARLES E. BOX

Chairman

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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	:	**09-0306**
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Central Illinois Public Service Company d/b/a AmerenCIPS	:	
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	:	**09-0308**
Proposed general increase in electric delivery service rates. (Tariffs filed June 5, 2009)	:	
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Proposed general increase in gas delivery service rates. (Tariffs filed June 5, 2009)	:	
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DATED: April 29, 2010

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ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On June 5, 2009, Central Illinois Light Company d/b/a AmerenCILCO ("AmerenCILCO"), Central Illinois Public Service Company d/b/a AmerenCIPS ("AmerenCIPS"), and Illinois Power Company d/b/a AmerenIP ("AmerenIP") each filed with the Illinois Commerce Commission (“Commission”) new and/or revised tariff sheets for electric and gas service. AmerenCILCO, AmerenCIPS, and AmerenIP are each a wholly owned subsidiary of Ameren Corporation ("Ameren") providing residential, commercial, and industrial electric and gas service throughout their respective service areas. AmerenCILCO, AmerenCIPS, and AmerenIP are collectively hereinafter referred to as Ameren Illinois Utilities ("AIU"). The new and revised tariff sheets ("Proposed Tariffs") proposed changes in electric and gas rates and the establishment of new riders, to be effective July 20, 2009. On July 8, 2009, the Commission entered six Suspension Orders suspending the Proposed Tariffs for each company to and including November 1, 2009 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. The Suspension Orders identify the specific tariff sheets filed by AIU. Upon suspension, AmerenCILCO's electric and gas filings became identified as Docket Nos. 09-0306 and 09-0309, respectively; AmerenCIPS' electric and gas filings became identified as Docket Nos. 09-0307 and 09-0310, respectively; and AmerenIP's electric and gas filings became identified as Docket Nos. 09-0308 and 09-0311, respectively. On October 7, 2009, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including May 1, 2010.

AIU posted a notice of the filing of the proposed rate increases in each of its business offices and published a notice twice in newspapers of general circulation within each of its service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, “Notice Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services.” In addition, AIU sent notice of the filing to its customers in bill inserts.

On July 10, 2009, the Administrative Law Judges notified AIU of certain deficiencies in its filings in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). The deficiency letters required AIU to submit various missing information and provide explanations of certain portions of the rate filings. AIU provided information in response to the deficiency letters on August 6, 2009.

Petitions seeking leave to intervene were filed by the People of the State of Illinois through the Attorney General (“AG”), the City of Champaign (“Champaign”), Citizens Utility Board (“CUB”), AARP,[1] System Council U-05 of the International Brotherhood of Electrical Workers, AFL-CIO, an association consisting of Local Unions 51, 309, 649, 702, and 1306 ("IBEW"), Grain and Feed Association of Illinois ("GFA"), Kroger Company ("Kroger"), Constellation NewEnergy, Inc. ("CNE"), Constellation

[1] In 1999, the "American Association of Retired Persons" changed its name to simply "AARP," in recognition of the fact that individuals do not have to be retired to be members.

NewEnergy-Gas Division, LLC ("CNE-Gas"), and Charter Communications, Inc. The University of Illinois, Air Products and Chemicals Company, Archer-Daniels-Midland Company, Cargill, Inc., Caterpillar, Inc., ConocoPhillips Corporation, Enbridge Energy, LLC, Illinois Cement Company, Linde NA, Inc., Olin Corporation, Tate and Lyle Ingredients Americas, Inc., United States Steel Corporation, Viscofan USA, Inc. and Washington Mills Hennepin, Inc. also intervened as members of the Illinois Industrial Energy Consumers (—IIEC"). All of the petitions to intervene were granted. The Cities of Urbana, Decatur, and Bloomington and the Town of Normal entered appearances pursuant to Section 10-108 of the Act. Together, with Champaign, the municipalities are collectively hereinafter referred to as Local Government Interveners or "LGI." Commission Staff ("Staff") participated as well.

On September 29, October 5, October 27, and November 2, 2009, the Commission held a public forum in Springfield, Collinsville, Pekin, and Decatur, respectively, for the purpose of receiving public comment on the general increase in electric and gas rates proposed by AIU. These locations were selected because they represent some of the larger population centers in the AIU service areas. A transcript of each public forum is available on the Commission's e-Docket system.

Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on August 6 and December 10, 2009. Thereafter, evidentiary hearings were held on December 14 through December 17, 2009. Appearances were entered by counsel on behalf of AIU, Staff, the AG, LGI, CUB, AARP, GFA, IIEC, Kroger, and CNE-Gas.

At the evidentiary hearings, AIU called 31 witnesses to testify. The 31 witnesses include (1) Karen Althoff, a Regulatory Consultant employed by AmerenCILCO, (2) Ronald Amen, a Vice President with the consulting firm Concentric Energy Advisors, Inc. ("Concentric"), (3) James Blessing, Manager of Power Supply Acquisition at AmerenCILCO, (4) Chad Cloninger, Manager of Illinois Operations, Divisions I--III for AmerenCILCO, (5) Kenneth Dothage, Manager of Gas Supply for Ameren Energy Fuels and Services Company ("AFS"),[2] (6) Salvatore Fiorella, President and sole owner of SFIO Consulting, Inc., (7) Michael Getz, Controller of each AIU company, (8) David Heintz, an Assistant Vice President with Cencentric, (9) Daetta Jones, Manager of Customer Satisfaction and Business Optimization at AmerenCILCO, (10) Leonard Jones, Manager of Rates and Analysis for AmerenCILCO, (11) George Justice, Manager of Illinois Operations, Divisions IV--VI for AmerenCILCO, (12) Michael Kearney, Manager of Economic Development for Ameren Services Company ("AMS"),[3] (13) Charles Laderoute, President of the consulting firm Charles D. Laderoute, Ltd., (14) Mark Lindgren, Vice President of Corporate Human Resources for AMS, (15) Mark Livasy, Superintendent of Energy Delivery Illinois for AMS, (16) Randall Lynn, a Principal with the consulting firm Towers Perrin, (17) Kathleen McShane, President of and Senior Consultant with the economic consulting firm Foster Associates, Inc., (18)

[2] AFS is a subsidiary of Ameren that provides fuel and natural gas supply for all Ameren affiliates.
[3] AMS is the service company subsidiary of Ameren and provides various services to its affiliates, including AIU.

Robert Mill, Director of AmerenCILCO's Regulatory Policy and Rates Department, (19) Peter Millburg, Managing Supervisor of Regulatory Compliance for AmerenCILCO, (20) Craig Nelson, Vice President of Regulatory Affairs and Financial Services of each AIU company, (21) Lee Nickloy, Director of Corporate Finance for AMS, (22) Paul Normand, a Principal with the consulting firm Management Applications Consulting, Inc., (23) Michael O'Bryan, Senior Capital Markets Specialist in Treasury-Corporate Finance of AMS, (24) Ronald Pate, Vice President of Regional Operations for each AIU company, (25) Vonda Seckler, Managing Executive of Gas Supply for AFS, (26) David Sosa, a Vice President with the consulting firm Analysis Group, (27) Ronald Stafford, Managing Supervisor of Regulatory Accounting in AmerenCILCO's Regulatory Policy and Rates Department, (28) Bruce Steinke, Vice President and Controller of Ameren and AMS, (29) David Strawhun, a Career Engineer in Distribution Systems Planning for AmerenCILCO, (30) Terry Tate, AIU's Superintendent of Vegetation Management, and (31) Stephen Underwood, Manger of Gas Storage for AmerenCILCO.[4]

Thirteen witnesses testified on behalf of Staff. The Staff witnesses include (1) Richard Bridal, II, (2) Theresa Ebrey, and (3) Burma Jones, Accountants in the Accounting Department of the Financial Analysis Division of the Commission‘s Bureau of Public Utilities, (4) Janis Freetly and (5) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, (6) Christopher Boggs, (7) Cheri Harden, and (8) Philip Rukosuev, Rate Analysts in the Rates Department of the Financial Analysis Division, (9) Peter Lazare, a Senior Economic Analyst in the Rates Department, (10) Greg Rockrohr, a Senior Electrical Engineer in the Engineering Department of the Energy Division of the Bureau of Public Utilities, (11) Eric Lounsberry, Supervisor of the Gas Section in the Engineering Department, (12) Brett Seagle, a Gas Engineer in the Engineering Department, and (13) David Sackett, an Economic Analyst in the Policy Department of the Energy Division.[5]

IIEC offered four witnesses at the evidentiary hearings. IIEC‘s witnesses include Michael Gorman, Greg Meyer, Robert Stephens, and David Stowe from the consulting firm Brubaker & Associates, Inc. David Effron, a consultant specializing in utility regulation, and Steven Fenrick, an economist with the consulting firm Power System Engineering, Inc., testified on behalf of the AG and CUB. Christopher Thomas, CUB‘s Director of Policy, also testified on behalf of CUB. Kroger called Kevin Higgins, a principal at the consulting firm Energy Strategies, LLC, to testify. Jeffrey Adkisson, GFA Executive Vice President and Treasurer, testified for GFA. Steven Brodsky and Nancy Hughes, Senior Directors with the consulting firm R.W. Beck, Inc., offered testimony for LGI. Jason Kawczynski, an Associate of Volume Management for CNE-Gas, testified on behalf of CNE-Gas.

[4] Andrew Wichmann, a Financial Specialist in AmerenCILCO's Regulatory Policy and Rates Department, prepared written testimony in these proceedings. At the evidentiary hearings, his testimony was adopted by Mr. Stafford.
[5] Mary Everson, an Accountant in the Accounting Department, prepared written testimony in these proceedings. At the evidentiary hearings, her testimony was adopted by Ms. Ebrey.

AIU, Staff, GFA, Kroger, and IIEC each filed an Initial Brief and Reply Brief. The AG and CUB jointly filed an Initial Brief and Reply Brief. LGI, AARP, CNE-Gas, and IBEW each filed an Initial Brief, but no Reply Brief. A Proposed Order was served on the parties. AIU, Staff, IIEC, and LGI each filed a Brief on Exceptions and Brief in Reply to Exceptions. The AG and CUB jointly filed a Brief on Exceptions and Brief in Reply to Exceptions. Kroger and IBEW each filed a Brief on Exceptions, but no Brief in Reply to Exceptions. All of the Briefs on Exceptions and Briefs in Reply to Exceptions were considered in the preparation of this Order. Following the submission of AIU's response to a Post-Record Data Request by the Administrative Law Judges pursuant to Section 200.875 of 83 Ill.Adm.Code 200, "Rules of Practice" ("Part 200"), the record was marked Heard and Taken on March 25, 2010. Oral argument was heard by the Commission on April 13, 2010 pursuant to Section 200.850 of Part 200.

II. NATURE OF AIU’S OPERATIONS

Ameren formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIU covers roughly the lower two-thirds of Illinois. AmerenCILCO currently serves approximately 214,000 electric customers and 216,000 gas customers. AmerenCIPS currently serves approximately 393,000 electric customers and 185,000 gas customers. AmerenIP currently serves approximately 627,000 electric customers and 421,000 gas customers. All of AIU's operations are within Illinois, although an affiliate of AIU (Union Electric Company d/b/a AmerenUE ("AmerenUE")) provides utility service in Missouri. At one time, AmerenUE served the St. Louis Metro East area in Illinois. That area has since been subsumed within AmerenCIPS' service area. Certain electric tariff terms in the St. Louis Metro East area are different from the electric tariff terms for the remainder of the AmerenCIPS' service area. The St. Louis Metro East service area is therefore referred to as the AmerenCIPS-ME rate area. Other affiliates of AIU provide unregulated services.

III. AIU’S PROPOSED TEST YEAR AND REVENUES

AIU proposes to use the 12 months ending December 31, 2008 as the test year in this proceeding. No party objects to the use of this test year. The Commission concludes that the historical test year AIU proposes is appropriate for purposes of this proceeding.

The Proposed Tariffs reflect a total increase in delivery service revenues of approximately $225.8 million for all AIU electric and gas customers. AIU's original proposed changes in the delivery service operating revenues for each service type and territory are as follows:[6]

[6] The numbers contained in the table reflect only proposed delivery service revenues since it is only those revenues at issue in this proceeding.

	ELECTRIC		GAS	
	Revenue Change	% Change	Revenue Change	% Change
AmerenCILCO	$27,787,000	22.8	$8,836,000	11.8
AmerenCIPS	$50,562,000	21.5	$11,448,000	15.6
AmerenIP	$102,287,000	22.1	$24,922,000	14.6

AIU determined the originally requested revenues using varying returns on equity for the utility operations ranging from 11.25% to 12.25%.

Over the course of this proceeding, however, AIU lowered its total requested delivery service revenue increase to approximately $130 million. The pending proposed changes in the delivery service operating revenues for each service type and territory are as follows:

	ELECTRIC		GAS	
	Revenue Change	% Change	Revenue Change	% Change
AmerenCILCO	$17,088,000	14.0	$2,328,000	3.1
AmerenCIPS	$38,034,000	16.2	$5,420,000	7.4
AmerenIP	$59,854,000	13.0	$7,004,000	4.1

AIU determined the revised requested revenues using varying returns on equity ranging from 10.8% to 11.7%.

AIU's most recent electric and gas delivery service rate cases considered by the Commission were consolidated Docket Nos. 07-0585 through 07-0590. The Commission entered the Order in that matter on September 24, 2008 approving a total increase in electric and gas delivery service revenues of approximately $161,262,000.

IV. RATE BASE

A. Resolved Rate Base Issues

1. 2002 to 2006 Plant Additions

AIU witnesses Livasy and Getz sponsored testimony substantiating records and invoices of plant additions disallowed in AIU's 2006 and 2007 rate cases. Mr. Livasy's direct testimony also addresses concerns raised in the 2006 and 2007 rate cases that AIU's recordkeeping practices violated 83 Ill. Adm. Code 420, "The Preservation of Records of Electric Utilities," and 83 Ill. Adm. Code 510, "The Preservation of Records of Gas Utilities." Staff witness Ebrey proposed certain adjustments to historical plant additions, which Mr. Livasy accepted in his rebuttal testimony with certain minor corrections to Ms. Ebrey's calculation. The Commission finds the proposed level of plant additions for the period 2002 through 2006 agreed to by AIU and Staff to be reasonable and it is hereby approved.

2. 2007 to 2008 Plant Additions

To eliminate the plant addition sampling methodology as a contested issue in this proceeding, AIU and Staff agreed to a sampling methodology to be utilized in Staff's review of AIU's 2007 and 2008 plant additions. Staff witness Bridal reviewed the 2007 and 2008 plant additions using the stipulated sampling methodology and initially identified 22 purported misstatements out of 827 transactions reviewed. Eleven of these misstatements were subsequently rectified to Mr. Bridal's satisfaction. AIU also proposed additional adjustments to Mr. Bridal's adjustment relating to easement transactions and invoices with offered discounts. Mr. Bridal accepted AIU's plant addition adjustments as presented in Ameren Ex. 29.8.

Additionally, Staff witness Rockrohr reviewed information about certain plant addition projects placed in service since AIU's last rate case filing and included in AIU's rate base in this proceeding. AIU witness Pate discusses additions to plant in service included in AIU's Schedule F-4 filings. Mr. Rockrohr initially recommended adjustments to AIU's rate base to remove the costs for three specific projects: AmerenCILCO's renovation of a purchased building (―Washington Street Renovation"), AmerenIP's NERC-related compliance project (―Transmission Plant"), and AmerenCIPS' relocation of the Pana East Substation. AIU in rebuttal accepted Mr. Rockrohr's adjustment to remove the Transmission Plant from AmerenIP's rate base and made similar adjustments to rate base for AmerenCILCO and AmerenCIPS to remove analogous NERC-related costs. AIU also provided Mr. Rockrohr with additional information about the contested AmerenCILCO and AmerenCIPS projects, including a revision to its proposed allocation for recovery of costs for the contested AmerenCILCO Washington Street Renovation. In rebuttal, Mr. Rockrohr accepted AIU's proposed allocation of costs for the AmerenCILCO Washington Street Renovation project. The only 2007-2008 plant addition project still contested is AmerenCIPS' project to relocate the Pana East Substation.

The Commission has reviewed the information provided by AIU and Staff. With the exception of the costs associated with relocating the Pana East Substation, which is addressed below in this Order, the Commission finds the proposed 2007 and 2008 plant additions to which Staff and AIU agree to be reasonable and hereby approves them.

3. Liberty Audit Pro Forma Adjustment

AIU's direct case proposed a pro forma adjustment to rate base for 2009 and 2010 expenditures associated with the implementation of certain audit recommendations of the Liberty Consulting Group. The audit reviewed AIU's response to certain major weather events impacting service to customers. Staff recommended that this pro forma adjustment be disallowed. In order to reduce contested issues, AIU is no longer seeking recovery of 2009 and 2010 Liberty-related expenditures in this proceeding. AIU indicates that recovery of these expenditures instead is now being sought through a rider in Docket No. 09-0602. The record in this proceeding supports a finding that Staff's pro forma adjustment to rate base for 2009 and 2010 expenditures associated with implementation of the Liberty Consulting Group recommendations should be accepted.

4. Lincoln Storage Field Sulfatreat

Staff witness Seagle initially recommended that the Commission deny AmerenCILCO‘s request to recover the costs to install a fourth Sulfatreat vessel at the Lincoln Storage Field because it failed to adequately support the need for the installation. In response, AIU witness Underwood provided additional information on the Sulfatreat vessel at the Lincoln Storage Field, including a net present value analysis. Based on his review of Mr. Underwood‘s testimony and accompanying exhibits, in conjunction with a visit to the Lincoln Storage Field, Mr. Seagle concludes that AmerenCILCO has provided sufficient information to justify the installation of a fourth Sulfatreat vessel at the Lincoln Storage Field. As the Commission understands it, Staff has effectively withdrawn its proposed adjustment and there is no contested issue to be decided with regard to this issue.

5. Materials and Supply Inventory

Staff proposed an adjustment for both AIU‘s electric and gas utilities to reduce their materials and supplies inventory (including gas in storage) (—M&S Inventory”) by the amount of accounts payable associated with the purchase of materials and supplies. Staff asserts that such an adjustment is necessary because AIU‘s shareholders have no investment in an inventory account until the related account payable has been paid. In order to reduce the number of contested issues, AIU agreed to adjustments for the General Materials and Supplies and Gas Stored Underground components of the M&S Inventory. AIU, however, continued to disagree with Staff‘s calculation of the portions of the M&S Inventory in accounts payable.

Eventually, Staff and AIU agreed on a methodology for calculating the accounts payable portion of AIU‘s M&S Inventory. The parties agreed that the General Materials and Supplies component of the total Materials and Supplies Balances will be reduced by an Accounts Payable amount calculated by multiplying the 13 month average balance of general materials and supplies by an accounts payable percentage (10.53%) based on payment lead days for the Operations and Maintenance ("O&M") component of the appropriate AIU lead-lag study. The parties further agreed that the Gas Stored Underground component of Materials and Supplies Balances will be reduced by an Accounts Payable amount calculated by multiplying the 13 month average balance of Gas Stored Underground by an accounts payable percentage (6.63%) based on payment lead days for the purchased gas adjustment ("PGA") component of the appropriate AIU lead-lag study.

As the Commission understands it, except for the value of gas in storage, AIU and Staff have agreed on how the M&S Inventory should be computed for purposes of this proceeding. The discussion of the value of gas in storage is addressed below in this Order. With regard to the remaining components of M&S Inventory, the Commission finds the agreement between AIU and Staff to be reasonable and it is hereby approved.

6. Gas Tapping Fee

The Gas Tapping Fee, also known as the pro rata upfront charge for connecting with the AmerenIP gas facilities, is an $850 fee, charged to connect new home construction to the main gas line. AIU proposes to eliminate the gas tapping fee. In response, Staff agrees that the fee should be eliminated, but suggests a slight adjustment to the AmerenIP gas rate base, in order to correct AIU‘s calculations of the fee. Because Staff‘s adjustment is simply based on AIU‘s response to Staff data request ("DR") RWB 6.02, AIU agrees to the adjustment. The Commission finds the agreement between Staff and AIU regarding the Gas Tapping Fee to be reasonable and it is hereby approved.

7. Error Regarding A Sulfatreat Change Out

Staff witness Jones presented an adjustment to remove a duplicate charge associated with a Sulfatreat change out. The error was identified by AIU in its response to Staff data request ENG 2.08. AIU does not oppose Staff‘s adjustment. The Commission finds Staff's proposal to remove a duplicate charge to be reasonable and it is hereby approved.

B. Contested Rate Base Issues

1. Pro Forma Plan Additions (2009-2010)

a. AIU Position

AIU proposed a pro forma adjustment to rate base for capital plant additions to be placed into service through May 2010. Staff originally proposed to include in rate base only pro forma capital additions through August 2009, but later recommended allowance of known and measurable pro forma capital additions through February 2010. To limit the number of contested issues, AIU subsequently agreed with Staff‘s recommendation. AIU says no party previously challenged the appropriateness of AIU's and Staff‘s adjustment, nor did any party, other than Staff, previously challenge the appropriateness of AIU‘s proposal to include certain post-test year plant additions in rate base.

Despite having remained silent in testimony, AIU complains that AG/CUB now argues that certain strings should be attached to approval of the adjustment. Specifically, AG/CUB argues that because of alleged discrepancies between budgeted and actual spending on all capital additions for the first nine months of 2009, AIU‘s pro forma capital additions should be subject to verification and true-up based on actual plant additions, as was done in Commonwealth Edison Company‘s (―ComEd”) last rate case, Docket No. 07-0566.

According to AIU, the parties‘ agreement to file a reconciliation in Docket No. 07-0566 is not a reason to require that one be filed here. AIU says the true-up procedure that occurred in the ComEd proceeding was the result of a stipulation between the utility and Staff. AIU argues that stipulations are ordinarily the product of a give-and-take process. AIU indicates it was not privy to whatever negotiations occurred between ComEd and Staff that resulted in ComEd‘s agreement to file a post-hearing reconciliation of forecasted versus actual plant additions. AIU insists that at no point in this proceeding, until now, has anyone suggested that AIU should file a similar reconciliation or true-up.

In AIU's view, absent a stipulation or other unusual circumstances, there is no basis to require AIU to file a reconciliation of its pro forma plant adjustment for plant additions. AIU states that Section 287.40 of 83 Ill. Adm. Code 287, "Rate Case Test Year" ("Part 287"), allows pro forma adjustments for ―known and measurable changes” to operating results and plant investment. AIU insists that its pro forma capital additions through February 2010 meet the known and measurable requirement. AIU contends that this means that the capital additions are known, and that the cost of these investments is determinable. AIU asserts that no one disputes this and believes there is no need for a post-hearing reconciliation to confirm that which is already known, measurable, and determinable.

AIU claims its actual capital expenditures historically have exceeded the capital budgets. AIU contends that the so-called ―discrepancies” between its total budgeted and actual capital spending relied on by AG/CUB do not prove that AIU‘s budgets are somehow ―unreliable.” AIU also asserts that they do not establish a pattern of underspending. AIU says the data does not even look at AIU‘s actual spending for the entire 2009 calendar year; it is limited to amounts budgeted and booked for the first nine months of 2009. AIU insists that this limited snapshot necessarily does not include the amounts booked in the final quarter of 2009 as projects are completed and put in service. In addition, AIU claims AG/CUB is comparing apples and oranges. AIU says the data relied on by AG/CUB are ―the actual and budgeted total capital expenditures” for each AIU electric and gas utility, excluding transmission. AIU says this data shows budgeted and spent dollars for all capital additions, not just spending for the specific plant additions included in AIU‘s pro forma adjustment. According to AIU, amounts budgeted and spent on new business, which were not included in the pro forma adjustment, are included in this data. AIU also says that amounts budgeted and spent on specific projects not included in the pro forma adjustment are also in this data. AIU claims that as a result, the data solely relied on by AG/CUB does not justify the imposition of a post-hearing reconciliation and true-up.

AIU contends that opening up the record to reconcile forecasted versus actual plant additions would place the Commission on a slippery slope. AIU claims it would invite parties to challenge expenditures after-the-fact and outside the normal evidentiary process. AIU also asserts that it would promote a lack of discipline among parties to ensure that pro forma capital additions fully satisfy the known and measurable requirement. If pro forma capital additions become subject to after-the-fact reconciliation, AIU believes there would be less incentive during the normal hearing process to make sure that these adjustments are documented with the same precision that Staff and the Commission ordinarily demand. In AIU's view, AG/CUB's proposal is not a good idea.

b. AG/CUB Position

AG/CUB reports that AIU proposes pro forma adjustments to include post-test year plant additions through February 2010 in the test year rate bases. AG/CUB says Commission rules allow such adjustments only to incorporate all known and measurable changes in the operating results of the test year. AG/CUB also say these adjustments must be reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable. AG/CUB indicates that the pro forma adjustments to plant in service are based on budgets and forecasts. AG/CUB argues that based on the experience to date in 2009, AIU's budgets of plant additions have not been especially reliable.

According to AG/CUB, through September 2009, the actual year-to-date capital additions were below the budgeted capital additions for each company. AG/CUB says the sole exception was AmerenCIPS electric, which would also have been well under budget except for the plant additions related to the May 2009 storm. AG/CUB alleges that the discrepancies between budgeted and actual plant in service numbers have been quite significant. AG/CUB states that AmerenCILCO electric's actual capital additions were below budget in every month shown, and through September 2009, the actual year to date capital additions were approximately 27% below budget.

Given the differences between forecasted and actual plant additions, AG/CUB argue that if the Commission allows AIU to include plant additions through February 2010 in pro forma rate base, AIU's forecasts should be subject to verification and true-up based on actual plant additions. AG/CUB claims this procedure was applied to the forecast of post-test year plant additions in the most recent ComEd rate case, Docket No. 07-0566, and resulted in a reduction of approximately $41 million to the projected plant additions included in the pro forma rate base by ComEd in that case. AG/CUB believes the same procedure should be applied to the AIU forecasts of plant additions.

c. Staff Position

Staff believes the Commission should approve its proposed adjustment to disallow plant additions beyond February 2010 from rate base. Staff accepted pro forma plant additions related to both specific and blanket projects that will occur through

February 2010 since AIU provided documentation that the projects were known and measurable. Staff does not oppose storm restoration costs resulting from the May 2009 “inland hurricane” that AIU included in its revised pro forma adjustment. Staff notes that AIU concurs with its proposed adjustments.

d. IBEW Position

IBEW agrees that AIU has met the necessary burden to recover the costs of pro forma plant additions for 2009-2010. IBEW believes that the projects are reasonably certain to occur and their costs are determinable. IBEW states that as the facilities are likely to be in service during the period that the new rates would go into effect, disallowing a recovery of the costs of plant additions through pro forma adjustments would not accurately reflect the actual costs of providing service to customers at that time.

IBEW asserts that an inadequate cost recovery could result in a deferral or cancellation of future planned plant additions and replacements, which could have a negative impact on the reliability of future service and the level of customer satisfaction. IBEW complains that deferral or cancellation of plant additions and replacements could also lead to less work for IBEW members and other Illinois workers, causing a further negative impact on economic conditions in Illinois.

e. Commission Conclusion

AIU, Staff, and IBEW agree that pro forma plant additions through February 2010 should be included in rate base. AG/CUB proposes that AIU's pro forma plant additions included in rate base be subject to verification and true-up based on actual plant additions using the method adopted in Docket No. 07-0566. AIU opposes AG/CUB's proposal.

The Commission observes that both AIU and Staff presented testimony that pro forma plant additions through February 2010 meet the requirements of Part 287, are known and measurable, and are determinable. The Commission finds that the record supports a conclusion that pro forma plant additions through February 2010 should be included in rate base. The AG/CUB's reconciliation proposal, however, has no basis in the record. The concept first appears in this proceeding in the AG/CUB's Initial Brief. Part 287 specifically provides for pro forma adjustments relating to "plant investment." Additionally, in numerous prior rate proceedings, the Commission has evaluated evidence regarding pro forma plant additions to determine whether such proposed adjustments should be included in rate base. The AG/CUB proposal, while utilized in Docket No. 07-0566, would constitute a deviation from the Commission's normal ratemaking process. The Commission is not willing to adopt AG/CUB's proposal over the objections of AIU when there is no evidentiary support for the proposal. Instead, the Commission finds that AG/CUB's proposal must be rejected in this proceeding.

2. Accumulated Reserve for Depreciation

a. AIU Position

AIU states that the plant in service component of rate base reflects the historical cost of the capital assets used to provide service, less accumulated depreciation on those assets as of December 31, 2008. Additionally, rate base includes certain known and measurable post-test year pro forma capital additions, which will be placed in service by February 2010. AIU says it included related adjustments to accumulated depreciation to reflect the additional depreciation associated with those pro forma capital additions. AIU indicates that Staff‘s calculation of accumulated depreciation and its impact on rate base reflects the same methodology used by AIU and endorsed by the Commission.

While they do not oppose a rate base adjustment to increase plant in service to reflect certain known and measurable pro forma capital additions, AIU indicates that AG/CUB and IIEC argue that an additional adjustment to the depreciation reserve is required to reflect an increase in accumulated depreciation on embedded plant (i.e., plant in service as of the end of the test year) that will occur in the 14-month period between the end of the 2008 test year and the month ending February 2010. AIU says these parties argue that their adjustment is supported by the Commission‘s pro forma adjustment rule contained in Part 287, and by the ―matching principle.” According to AIU, however, the Commission has already rejected AG/CUB's and IIEC‘s proposed additional adjustment to depreciation reserve, and their supporting arguments, in four prior cases. AIU believes these parties provide no new evidence or arguments that warrant a different outcome here. AIU maintains that the AG/CUB and IIEC adjustments violate basic ratemaking principles and the Commission‘s test year rules. AIU contends that the proposed adjustment creates a mismatch between the utility‘s test year plant in service and its depreciation reserve by effectively moving the depreciation portion of rate base to a future period outside of the test year. AIU argues this violates Section 287.40, which provides for known and measurable ―changes in plant investment” to a utility‘s test year plant in service, not changes in the utility‘s net plant or rate base at a future point in time outside of the test year.

AIU indicates that the recent Commission Order in Docket No. 07-0566 rejected arguments that Section 287.40 or the matching principle requires the additional depreciation reserve adjustment proposed by AG/CUB and IIEC. According to AIU, this adjustment was first proposed and rejected in Docket No. 01-0423, a ComEd rate proceeding. AIU says that the Commission found that to accept the adjustment would improperly shift the test year just for the accumulated depreciation reserve. AIU reports that the Commission again rejected the proposed adjustment in a subsequent ComEd proceeding, Docket No. 05-0597. AG/CUB's and IIEC‘s proposed depreciation reserve adjustment, AIU avers, was rejected for a third time in Docket Nos. 07-0241/0242 (Cons.), a rate proceeding involving North Shore Gas Company ("North Shore") and Peoples Gas Light and Coke Company ("Peoples"). Finally, AIU indicates that the

Commission rejected the same proposed adjustment in ComEd's most recent rate case, Docket No.07-0566.

AIU states that in these consolidated proceedings, AG/CUB and IIEC again offer the same arguments that the Commission has previously considered and rejected. According to AIU, prior Commission Orders on this issue are clear that adjusting the test year depreciation reserve for embedded plant in service to include post-test year depreciation on that embedded plant violates the test year and pro forma adjustment rules contained in Sections 287.20 and 287.40. AIU contends that AG/CUB and IIEC seek to simply bring the depreciation reserve on the entire embedded plant forward through February 2010, in effect moving one element of rate base to a future period while all other elements of the revenue requirement remain based on a historical period. Contrary to serving the matching principle, AIU believes that AG/CUB's and IIEC‘s proposed adjustment expressly violates it.

AG/CUB's and IIEC‘s adjustments, AIU argues, also fail to meet the known and measurable requirement set forth in Section 287.40. AIU asserts that while the philosophical underpinnings of these parties‘ positions are the same, they rely on different assumptions, calculations, and extrapolations, which AIU believes to prove that estimating the depreciation reserve as of February 2010 is not the straightforward exercise they would have the Commission believe. Where two witnesses attempt the same adjustment under the same rationale and the results are $23 million apart, AIU contends the adjustment can not be said to represent a —known and measurable” change.

AIU expects AG/CUB and IIEC to argue that the Commission is not bound by its prior decisions, particularly given the dissenting opinion in Docket No. 07-0566. AIU claims the dissenting opinion, however, provides no basis for a majority of the Commission to do an about face on this issue. The dissenting opinion, AIU avers, is largely a repackaged version of the same arguments that AG/CUB, IIEC and others have made in prior proceedings. AIU believes this is evidenced by the fact that the dissenting opinion relies on IIEC's and CUB‘s legal briefs to support its conclusions.

In AIU's view, while it is one thing to say that the Commission is not strictly bound by precedent, it is quite another to say that the Commission may freely disregard precedent. AIU says the Illinois Supreme Court has recognized that —[t]he concept of public regulation includes of necessity the philosophy that the commission shall have power to deal freely with each situation as it comes before it, regardless of how it may have dealt with a similar or even the same situation in a previous proceeding.” (AIU Initial Brief at 23, citing Mississippi River Fuel Corp. v. Illinois Commerce Comm‘n (1953), 1 Ill. 2d 509, 513, 116 N.E.2d 394, 396-97 ("Mississippi River Fuel")) AIU contends that the Commission‘s discretion to decide issues on a case-by-case basis is not without limitation. AIU says the Illinois Supreme Court has recognized that where the Commission determines to depart from past practice, it may not do so in an —arbitrary or capricious” manner. (Id., citing United Cities Gas Co. v. Illinois Commerce Comm‘n (1994), 163 Ill. 2d 1, 27-28, 643 N.E.2d 719, 732) AIU argues that regardless of whatever authority the Commission has to depart from prior decisions, ―the Commission cannot violate the [Public Utilities] Act or its own rules." (Id. at 23-24, citing Business and Professional People for Public Interest v. Illinois Commerce Comm'n (1989), 136 Ill. 2d 192, 228, 555 N.E.2d 693,709 ("BPI I"))

AIU suggests that AG/CUB and IIEC may also argue that to the extent the Commission relies on prior decisions, the Commission should reach a result consistent with the Order in Docket Nos. 02-0798/03-0008/0009 (Cons.). AIU states that in that proceeding, which were gas rate cases by AmerenCIPS and AmerenUE, the Commission found that where historical net plant in service is either declining or relatively static, as in these cases, post-test year pro forma increases to plant in service require further analysis. AIU says the Commission found that in a situation where there is a demonstrated trend of significant increases of net plant in service, the Commission might be inclined to find that post test year capital additions should be reflected in rate base. AIU indicates that the Commission therefore disallowed AmerenCIPS' post-test year capital additions, but partially allowed the additions for AmerenUE to the extent that they exceed increased accumulated depreciation.

According to AIU, in Docket Nos. 02-0798 et al. (Cons.), the evidence showed the AmerenCIPS' net plant in service was declining or static. In Docket Nos. 01-0423, 05-0597, 07-0241/0242 (Cons.), and 07-0566, AIU claims that the evidence showed that the utilities' net plant in service had been increasing. AIU asserts that it is undisputed here that AIU's net plant in service has been increasing.

AIU believes AG/CUB and IIEC also may suggest that the facts and circumstances of this proceeding are somehow different from Docket No. 07-0566 and the other prior decisions on this issue, therefore justifying a different outcome. AIU insists that the relevant and controlling facts and circumstances are no different. AIU says that AIU's accounting for depreciation on embedded plant and pro forma capital additions is functionally equivalent to the adjustments ComEd made in Docket No. 07-0566. AIU claims its proposal to include post-test year depreciation on test year embedded plant is functionally equivalent to the adjustment proposed in Docket No. 07-0566. In AIU's view, these parties can not make a clear showing as to the appropriateness of such a change by way of proper evidentiary and legal support to consider such departures from settled precedent.

AIU states that fundamentally, the depreciation reserve issue revolves around the interpretation of the Commission's rule for pro forma adjustments. AIU claims that the purpose, text, and prior decisions interpreting Section 287.40 lead to the conclusion that the rule prohibits the depreciation reserve adjustment proposed by AG/CUB and IIEC. AIU says the issue confronting the Commission is whether ―ratemaking norms" or other policy considerations warrant a change in interpretation of Section 287.40. AIU states that the Commission is bound by the Act and its rules. According to AIU, it can not ignore or circumvent its prior interpretation of Section 287.40 based on a subjective determination that ―ratemaking norms" or ―standard regulatory accounting" warrant such a departure.

AIU indicates that Staff's recommended rate bases do not include intervenors' proposed depreciation reserve adjustment. AIU complains that Staff appears to invite the Commission to make this adjustment anyway. In AIU's view, Staff's position is at best ambiguous and at worst disingenuous. According to AIU, Staff provides no useful guidance to the Commission in resolving this issue and its brief on this issue should be ignored.

AIU asserts that Staff is apparently attempting the same reversal of position in these proceedings that it unsuccessfully attempted in Docket Nos. 07-0241/0242 (Cons.). AIU states that in those dockets, Staff accepted the company's proposed pro forma adjustment for capital additions, without proposing an additional adjustment to depreciation reserve for embedded plant. According to AIU, it was not until the Reply Brief that Staff reversed course and withdrew its objection to the depreciation reserve adjustment. According to AIU, the Order in those dockets rejected the adjustment, despite Staff's changed position in its Reply Brief.

In AIU's view, Staff can not take one position during the evidentiary phase of the case and an opposite position during the briefing stage. According to AIU, to allow this to happen is to deny AIU and other parties the right to fully develop the record through submitted testimony and cross examination. AIU also says Staff can not argue that because it has not previously taken an explicit position on an adjustment, there is no inconsistency in taking a position now. AIU insists that Staff did take a position. Despite AG/CUB and IIEC testimony recommending the adjustment, AIU says Staff's rate base recommendation includes pro forma plant additions through February 2010 without any adjustment for additional depreciation on embedded plant. AIU believes that declining to make this adjustment is tantamount to rejecting it.

AIU says the arguments in Staff's Initial Brief are entirely new. In its Initial Brief, AIU indicates that Staff characterizes the dispute over this adjustment as a battle between competing principles of ―regulatory lag" and the ―matching principle." AIU argues that no testimony has been offered in this case, by Staff or anyone else, to support Staff's conclusion. According to AIU, Staff says that there is a point in which the remedy for regulatory lag intentionally overstates anticipated costs, but doesn't explain what that ―point" is or whether this ―point" has been reached in this case. AIU also complains that Staff has not identified what costs are allegedly overstated, how much they are overstated, or at what ―certain point in time" they are overstated. AIU says there is no testimony in the record that regulatory lag needs to be ―balanced" with the matching principle. AIU claims Staff should have made an adjustment if they believe that net plant is ―overstated" in any way.

AIU says AG/CUB and IIEC argue that AIU's accounting for depreciation reserve violates Section 9-211 of the Act, which provides that rate base may include only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers. AIU contends that the Commission considered this argument and rejected it without comment in Docket No. 07-0566. AIU says the intervenors equate the term —value” with —net plant” and argue that because —net plant” accounts for depreciation, depreciation on embedded plant must be included in the —value” of investment. According to AIU, the purpose of Section 9-211 of the Act is to allow only those investments which are prudently incurred and used and useful in providing service to be included in rate base. AIU argues that the statute does not dictate how the Commission must calculate rate base, either in the aggregate or with respect to any individual element thereof. AIU claims this interpretation is confirmed by the statute immediately preceding, Section 9-210. AIU asserts that Section 9-210 gives the Commission ample discretion to ascertain the —value” of rate base by allowing pro forma capital additions without deducting additional depreciation for embedded plant. AIU insists that Section 9-211 does not limit the Commission‘s discretion, and does not mandate the adjustment proposed by intervenors.

AG/CUB argues that AIU proposes a test year ending February 2010 for plant in service and a test year ending December 31, 2008 for depreciation reserve. AIU contends that this misstates AIU‘s position. AIU states that test year plant in service has been calculated, net of depreciation, as of December 31, 2008. AIU says no depreciation adjustments have been proposed for embedded plant in service. In AIU's view, the pro forma capital additions are a separate category of plant in service. AIU says these additions have been calculated, also net of depreciation, as of February 28, 2010. AIU states that the recognition of depreciation on the pro forma capital additions reflects changes affecting the ratepayers in plant investment associated with these additions. AIU insists this is what Section 287.40 allows. What the rule does not allow, AIU argues, is the recognition of additional depreciation on embedded plant, a different category of plant in service separate and unrelated to the pro forma additions. AIU contends that AG/CUB‘s proposal improperly moves the test year forward for the depreciation reserve for embedded plant, based solely on attrition (i.e., the decline in value of an asset over time as recognized in depreciation expense), which is prohibited by Section 287.40.

AIU says the entire section of the Order in Docket Nos. 02-0798 et al. (Cons.) discussing pro forma capital additions is just over four pages and claims the Commission conclusion section of the Order does not even discuss test year or pro forma adjustment rules. AIU asserts that there is no discussion of if, how, or why depreciation reserve on embedded plant should be calculated. According to AIU, it is not clear based on the face of the Order that depreciation on embedded plant was included in any of the utilities‘ rate base.

AIU asserts that the Order in Docket Nos. 07-0585 et al (Cons.) devotes 12 pages of discussion to this issue, including an analysis of Section 287.40. AIU says the Commission concluded that a major concern regarding the adjustment to test year depreciation, pointed out in the Order in Docket No. 05-0597, has not been resolved in this case. AIU asserts that the proposed adjustment does not correlate with any pro forma adjustments. AIU states the Commission found that the proposal merely takes one part of the rate base and moves it one additional year into the future.

AIU asserts that AG/CUB and IIEC also fail to explain how their interpretation of Section 287.40 should be applied in future cases. AIU says these intervenors argue that the magnitude of AIU‘s pro forma adjustment is the practical equivalent of moving the entire balance of net plant forward 14 months. It is on this basis that they argue the entire depreciation reserve for embedded plant should also be moved forward 14 months. AIU contends that they do not explain what should happen if, for example, a utility proposes a pro forma adjustment to include only a few post-test year capital projects in rate base, or perhaps one significant addition. AIU says that by their logic, the depreciation reserve on all embedded plant would have to be brought forward to whatever date the pro forma addition(s) was projected to be in service. AIU claims this could result in the depreciation reserve for embedded plant exceeding the value of gross plant for the pro forma additions. AIU complains that the utility would be financially penalized for making such an adjustment. AIU says AG/CUB and IIEC‘s interpretation seemingly compels this absurd result.

According to AIU, AG/CUB's and IIEC‘s arguments that AIU has violated the matching principle are somewhat intertwined with their test year arguments. AIU says these arguments have also been considered and rejected multiple times. AIU contends that it is AG/CUB who expressly proposes a mismatch by deducting post-test year depreciation on test year embedded plant. AIU claims that if AG/CUB were truly interested in ―matching” all depreciation, it would also recommend adding 14 months of depreciation expense to the revenue requirement. AIU says its failure to do so demonstrates the selective and one-sided nature of its adjustment.

IIEC suggests that in order to comply with the matching principle, if a pro forma adjustment can be made, it must be made. AIU says the premise for this argument seems to be that because it is mathematically possible to calculate the depreciation reserve for embedded plant as of February 2010, this adjustment must be made to offset the increase in plant. AIU maintains that pro forma adjustments <u>may</u> be made for plant in service. AIU states that its adjustments include depreciation on plant in service associated with the pro forma additions. AIU argues that whether depreciation on embedded plant can be mathematically determined as of February 2010 is irrelevant to the calculation of depreciation for plant in service constituting the pro forma additions. Regardless of what any accounting literature says about the matching principle, AIU insists that the Commission‘s test year and pro forma adjustment rules prohibit selectively incorporating post-test year changes to test year rate base. AIU believes they do not have to be made in every instance where it is mathematically possible to calculate an element of rate base or operating income within 12 months of the end of the test year.

IIEC argues that the decision in Docket No. 07-0566 provides evidence of the consequences of approval of unbalanced pro forma adjustments that was not available in previous cases, and therefore supports a different result in this case. AIU contends that IIEC's analysis is an apples-to-oranges comparison of gross plant with net plant and asserts that this analysis proves nothing. AIU believes that all IIEC has shown is that if the Commission had adopted the adjustment proposed here in Docket No.

07-0566, ComEd would have had a lower revenue requirement. AIU says this conclusion is obvious without an analysis because adding post-test year depreciation to test year embedded plant will necessarily lower the revenue requirement. AIU contends that whether a pro forma adjustment increases or decreases the revenue requirement is not the standard for determining whether the adjustment is appropriate.

AIU says that in Docket No. 07-0566, IIEC argued that if its adjustment was not adopted, ComEd's net plant would be overstated and the Commission rejected this argument. AIU states that IIEC now argues that because the Commission's rejected its adjustment, ComEd's net plant was overstated, resulting in ComEd over-earning its authorized return. AIU says that in Docket No. 07-0566, IIEC's argument was ex ante, here it is ex post, but ultimately it is the same argument.

AIU says the only new argument that AG/CUB makes is that the Commission should just go ahead and make the depreciation reserve adjustment because AIU will not be ―penalized" if it does. AIU states that reasonable minds can disagree over whether an adjustment of this magnitude constitutes a penalty. AIU believes that whether it is a penalty is completely irrelevant to the discussion. AIU says the Commission's test year rules prohibit deducting even $1 for post-test year depreciation on test year embedded plant.

b. AG/CUB Position

AG/CUB indicates that AIU is proposing to adjust rate base for post-test year additions to plant in service to account for proposed plant additions through February 2010. AG/CUB observes that AIU does not recognize other changes that will also be taking place during that same pro forma time period, specifically the increase in accumulated depreciation on that plant in service. AG/CUB argues that AIU's determination of plant in service as of February 2010 and depreciation reserve as of December 2008 is an unbalanced and inconsistent determination of the pro forma test year rate base.

According to AG/CUB, the Commission's test year rules and the Act require the value of a utility's investment that is used and useful be reflected in rates. If rate base is adjusted to recognize plant additions through February 2010, then AG/CUB believes it is reasonable and consistent that the growth on the accumulated reserve for depreciation be recognized through the same date.

AG/CUB states that AIU proposes inclusion in rate base of capital additions through February 2010, which results in an aggregate increase to rate base of $249,027,000. AG/CUB avers The Act requires that the Commission determine a facility is prudent as well as used and useful in providing utility service to the utility's customers before its costs are included in the utility's rate base. Further, AG/CUB says the Commission must determine that the costs of the new plant, or significant additions to an existing plant, are reasonable. AG/CUB also asserts that the utility has the burden of proving that its investments meet these requirements.

AG/CUB emphasizes that Section 9-211 of the Act requires that 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. According to AG/CUB, the post-test year value of AIU's investment is the net value of the plant. AG/CUB says the net plant accounts for accumulated depreciation and recognizes that as plant additions become used and useful in providing service to customers, embedded plant depreciates. AG/CUB asserts that the Commission has no authority to simply ignore decreases in rate base value from the depreciation of embedded plant occurring because of the plant additions.

According to AG/CUB, AIU‘s request to include "extraordinary" increases to rate bases for post-year plant additions without reflecting the concomitant increase in accumulated depreciation would improperly inflate the rate base amounts by $169 million. AG/CUB argues that only with a recognition of the accumulated depreciation that occurs with the addition to rate base of pro forma plant additions can there be an accurate valuation of the rate base so as to ensure just and reasonable rates. In order to determine the rate of return ("ROR") upon the reasonable value of the property at the time it is being used for the public, AG/CUB avers that it becomes necessary to ascertain what that value is. AG/CUB is concerned that if adopted, AIU‘s proposal to recognize only the portion of pro forma plant additions that increases its rate base and failing to recognize the growth in depreciation reserve on embedded plant through that same time period would violate Section 9-211 of the Act.

AG/CUB says AIU opposes any adjustment to recognize the growth in depreciation reserve on embedded plant through February 2010. According to AG/CUB, the primary reason that AIU gives for opposing this adjustment is that it would violate the ―matching principle.” AG/CUB believe AIU's interpretation of the matching principle is completely inverted. AG/CUB states that utility rates are set based on a synchronized examination of all aspects of the utility‘s cost of service and sources of revenue, as well as other considerations such as the quality of service. AG/CUB claims that synchronization is the reason why a test year is used to set rates. 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. (AG/CUB Initial Brief at 6, citing Business and Professional People for the Public Interest v. Illinois Commerce Comm‘n, 146 Ill. 2d. 238 (1991) (―BPI II”))

According to AG/CUB, AIU's position appears to be based on the theory that the pro forma adjustment for plant additions does not move the test year forward, that is, extend from 2008 through part of 2010, for other test year ratemaking elements. In AG/CUB's view, the very purpose of the adjustment is to restate the plant in service data from its balance as of December 2008 to its balance as of February 2010. AG/CUB insists that any claim that such an adjustment does not move the test year forward for any portion of the test year is contrary to the purpose of the adjustments being proposed by AIU.

AG/CUB argues that AIU can not explain how stating the plant in service as of February 2010 but the depreciation reserve as of December 2008 constitutes an appropriate “matching” as that term is typically used by regulators. In AG/CUB's view, stating plant in service as of February 2010 but depreciation reserve as of December 2008 is the textbook definition of a mismatch. AG/CUB believes that to correct this mismatch, it is necessary to recognize growth in the depreciation reserve through February 2010. AG/CUB also asserts that Section 287.40 requires all known and measurable changes in plant investment be included in a pro forma adjustment to a historical test year. AG/CUB says AIU proposes a test year ending February 2010 for plant in service and a test year ending December 31, 2008 for depreciation reserve.

According to AG/CUB, AIU suggests that any recognition of the growth in deprecation reserve that offsets these post-test year plant additions would “penalize” AIU. AG/CUB is proposing to recognize post-test growth in the depreciation reserve of $169 million, in the aggregate, as an offset to the post test year plant additions. Thus, even after properly matching the depreciation reserve to the plant additions through February 2010, AG/CUB says the pro forma adjustment for post-test year growth of net plant in service is still $80 million in the aggregate ($249 million - $169 million). AG/CUB submits that a pro forma adjustment for post-test year growth of net plant in service of approximately $80 million in no way “penalizes” the AIU.

AG/CUB states that in Docket Nos. 02-0798 et al. (Cons.) and Docket No. 01-0432 the Commission accepted adjustments to recognize post test-year growth in the depreciation reserve. AG/CUB indicates that AIU asserts that the reason stated in the Commission order in Docket Nos. 02-0798 et al. (Cons.) for a different treatment was the lack of a demonstrated trend of significant increases of net plant in service. AG/CUB says AIU asserts that in Docket No. 01-0432, the treatment was based on an agreement between Staff and the company, with little discussion of the facts and circumstances relevant to that case. AG/CUB believes the opinions of AIU on this point are not useful for distinguishing these decisions from what AIU is proposing in the present case.

AG/CUB states that Commission decisions are not *res judicata*. (AG/CUB Initial Brief at 10, citing Mississippi River Fuel, 1 Ill. 2d at 513) According to AG/CUB, the Commission is required by law to decide each case on the merits of the record evidence. AG/CUB argues that the Commission may make a different determination if the evidence before it does not support the same result as in a previous case or supports a change in a prior Commission position. AG/CUB observes that the Illinois Supreme Court stated, “past precedent is not controlling, because the Commission is a legislative and not a judicial body, and generally its decisions are not *res judicata* in later proceedings before it . . .'” (Id., citing Citizens Utility Board v. Illinois Commerce Commission et al., 166 Ill. 2d 111; 651 N.E. 2d 1089, 1097 (1989) (“Citizens”)) AG/CUB insists that the Commission must base its decision on this issue on the record before it in this case and not on its findings in prior cases.

In AG/CUB's view, the suggestion that the Commission should "blindly" follow its prior decision on this issue is unsupportable because the Commission findings contained very little substantive discussion of the issue. AG/CUB says the Commission in Docket Nos. 07-0241/0242 (Cons.) stated that it was following its findings in Docket No. 05-0597. In Docket No. 07-0566, AG/CUB indicates the Commission majority stated that it was following its findings in Docket No. 05-0597 and Docket Nos. 07-0241/0242 (Cons.). AG/CUB also cites the Dissenting Opinion in Docket No. 07-0566, which it says demonstrates why the distinction offered by AIU is irrelevant in determining the applicability of these cases.

AG/CUB says AIU cites case law in its Initial Brief that highlights the prohibition on ―arbitrary and capricious" Commission rulings and asserts that adopting the AG/CUB position would amount to such prohibited behavior. AG/CUB claims that argument rings hollow. AG/CUB claims there is no basis for distinguishing the facts that led the Commission to adjust another utility‘s accumulated depreciation reserve to recognize the changes in embedded plant in Docket Nos. 02-0798 et al. (Cons.) from the instant case. AG/CUB says the finding in that case was correct and should inform the Commission‘s decision in the present case.

AG/CUB says in six other states within the last two years, none of these jurisdictions make a practice of allowing post-test year adjustments to rate base for routine plant additions without offsets for growth in the depreciation reserve. AG/CUB asserts that some of these jurisdictions do not allow adjustments for post-test year plant additions, and those that do require that growth in the depreciation reserve also be recognized. AG/CUB states that while AIU attempts to minimize the relevance of practices in other jurisdictions, it does not cite any other jurisdictions where the regulatory authorities "tolerate" a mismatch like AIU‘s proposal here. AG/CUB states that IIEC also identified where an AIU affiliate company in Missouri recently matched post-test year plant additions with depreciation reserve. AG/CUB claims there is no factual basis to treat AIU differently from AmerenUE in Missouri.

AG/CUB argues that because AIU‘s pro forma plant adjustment is based on budgets and forecasts, the derivative adjustment to depreciation reserve must necessarily entail certain assumptions and estimates. In AG/CUB's view, it is not surprising that two independent estimates of the necessary adjustment to the depreciation reserve associated with the pro forma plant additions would arrive at two different amounts. AG/CUB claims the adjustment to depreciation reserve is no less known and measurable than is AIU‘s own pro forma plant adjustment for plant additions. AG/CUB asserts that just as the uncertainties in the plant adjustment can be rectified by truing up the adjustment to the actual plant balances as of February 2010, the necessary adjustment to the depreciation reserve can also be computed when the actual balance of the depreciation reserve is available in February 2010.

AG/CUB contends that neither it nor IIEC seeks to bring the depreciation reserve on the entire embedded plant forward through February 2010. Rather, AG/CUB asserts that they both seek to bring the depreciation reserve on the embedded plant other than plant related to serving new customers forward through February 2010, to be consistent with AIU's pro forma adjustment for post-test year plant additions. AG/CUB states that the claim that AG/CUB and IIEC seek to have all other elements of the revenue requirement remain based on the historical period is a distortion of the record of the case. AG/CUB claims that neither it nor IIEC seek to eliminate AIU's pro forma adjustment for post-test year plant additions, and they both state that the proposed adjustments to depreciation reserve would not be necessary were it not for the pro forma adjustment for post-test year plant additions. (AG/CUB Reply Brief at 6-7)

AG/CUB argues that AIU's opposition to the pro forma adjustment to the depreciation reserve appears to be based on the "myth" that all other elements of the rate base that are used in the determination of its revenue requirement reflect the actual per books balances as of December 31, 2008. AG/CUB says this is not true. According to AG/CUB, the rate base can not be portrayed as reflecting actual test year balances when the largest element of rate base, plant in service, includes capital additions through February 2010. AG/CUB says AIU fails to explain how the inclusion of plant additions through February 2010 in pro forma rate base comports with its claim that all other elements of the revenue requirement remain based on the historical period.

c. IIEC Position

IIEC does not consider AIU's proposed pro forma increases to test year rate bases for planned post-test year plant additions to be separate -- or severable -- from recognition of the contemporaneous post-test year decreases to rate base that will be recorded as changes to accumulated depreciation. IIEC states that the Commission is permitted to include in AIU's ratemaking rate bases only AIU's plant in service (net plant), which can not be determined by looking at only one component of that calculated investment amount.

IIEC asserts that AIU overstates rate base as a result of a selective pro forma adjustment to reflect post-test year changes in rate base. IIEC indicates that AIU proposes to increase the gas and electric rate bases used to determine rates in this case, by the amount of each utility's planned post-test year plant additions through May 2010, a period of 17 months after the end of the 2008 test year chosen by AIU. According to IIEC, AIU proposes to add about a quarter-billion dollars in plant investment to its ratemaking rate base. IIEC avers AIU's proposed adjustment would ignore the decline in rate base value over the period of the plant additions due to depreciation the utilities are required to recognize on their books of account. Although AIU suggests that its proposed changes to recognize plant retirements and retirement-related depreciation also affected its additions to rate base, IIEC claims those items had no effect on net plant; the modifications simply removed these investments from both the asset and the liability components of rate base.

IIEC contends that rate base can increase or decrease over time, depending mostly on the change to ―net‖ utility plant investment. IIEC says the post-test year change in net utility plant investment represents the difference between gross plant additions less the change to accumulated depreciation or depreciation reserve that will occur during the same post-test year time period. According to IIEC, plant additions will not increase net plant dollar for dollar because the plant additions will be offset by increases to accumulated depreciation reserve that will occur during the same post-test year time period. IIEC asserts that because AIU accounted almost exclusively for the plant addition increases to gross utility plant while ignoring the contemporaneous offset of changes in accumulated depreciation, AIU overstated both its net plant and the rate base on which it is authorized to earn a return.

While IIEC did not contest the amount of AIU's plant additions, IIEC does oppose AIU's proposed unbalanced adjustment, because it overstates the rate bases and the cost of equity. IIEC has proposed what it considers an appropriate correcting adjustment, which is easily modified to match whatever period of plant additions the Commission may approve.

AIU indicates that its proposed adjustment was constructed to mimic the adjustments accepted by the Commission's decisions in recent rate cases. IIEC states that both cases are now the subject of appellate judicial review. IIEC says AIU has offered no other substantive support for its proposed rate base adjustment that can stand on its own. According to IIEC, AIU depends entirely on transferring the result of those decisions to a determination on this record. IIEC asserts that the reasons those decisions can not be applied fall into two categories. IIEC says the first group consists of legal requirements, both statutory and regulatory. The second group, IIEC avers, comprises matters of fact established by the evidence in this record, on which the Commission must base its decision. IIEC believes that AIU's proposed adjustment is not supported by the manifest weight of the evidence.

According to IIEC, the record in this proceeding is the exclusive lawful basis of a decision in this case. IIEC insists that the record in this proceeding is substantively distinguishable from the record of any of the cited cases. IIEC contends that the Commission is constrained in its review of this record only by its duty to explain departures from established past policies, with its reasoning articulated in its decision. IIEC believes the prior Commission decisions cited by AIU are not a bar to a review of the evidence and arguments that were not a part of earlier records. IIEC recommends that the Commission reject suggestions that this issue has been settled and is beyond re-examination.

According to IIEC, AIU's Initial Brief relies completely on a selection of prior Commission decisions that were based on different and distinguishable records, for different utilities, at different times, under different sets of facts. In support of its position, IIEC cites the dissenting opinion in Docket No. 07-0566. IIEC also opines that AIU's Initial Brief does not provide a substantive examination of the circumstances in prior cases, or even the substantive evidence of this record. AIU argues that the —relevant and controlling facts and circumstances" are the same, because its proposed unbalanced adjustment is functionally equivalent to the adjustments ComEd made in Docket No. 07-0566.

IIEC states that Section 9-211 of the Act limits the Commission to including in a utility_srate base only the value of such investment which is both prudently incurred and used and useful in providing service to public utility customers. IIEC asserts that the value of a utility‘s rate base investment is affected by both the addition of new investment and the decline in investment value due to plant depreciation. In IIEC's view, AIU asks the Commission to ignore one-half of that rate base calculation by approving its unbalanced pro forma adjustment.

IIEC argues that AIU‘s proposed adjustment, which would calculate AIU‘s rate base using post-test year increases to plant in service, from plant additions, without taking account of the post-test year decreases to plant in service recorded as accumulated depreciation, will produce a rate base amount in excess of the value of plant investment used to provide service. In IIEC's view, AIU‘s proposed adjustment asks the Commission to violate the Act‘s express limitation on the Commission‘s authority to include in rate base amounts in excess of the value of the plant used to provide service -- net plant. IIEC also contends that no party disputes that an excessive rate base also would result in a revenue requirement that exceeded the utility‘s cost of capital. IIEC believes that rates set on such an excessive basis would not be just and reasonable and can not lawfully be approved by the Commission.

IIEC contends that the adjustment is inconsistent with any reasonable reading of Section 287.40 and with standard regulatory accounting conventions. IIEC also argues that neither AIU nor the prior Commission decisions on which AIU relies provide any authority for the Commission's departure from standard regulatory accounting and test year principles, as defined by the Illinois Supreme Court. IIEC asserts that the proposed adjustment violates test year principles, and it is not representative of the matched costs and revenues that will exist when rates set in this case will be in effect.

IIEC indicates that AIU proposed a 2008 historical test year for setting rates in this case. Under the Commission‘s test year rules, IIEC says utility costs and revenues are matched over that consistent time period, the test year. According to IIEC, data from outside that test year can be considered in setting rates only on the specific conditions defined in the Commission rules, including Section 287.40, which governs the use of post-test year data. IIEC says that section contemplates balanced adjustments for "all known and measurable changes" affecting ratepayers, in the components of AIU's revenue requirement. IIEC contends that AIU‘s pro forma adjustment recognizes post-test year plant investment increases that are not offset by the contemporaneous decline in plant investment value attributable to depreciation. According to IIEC, AIU proposes smaller offsets that avoid including one of the two principal components of a proper calculation of rate base investment value. IIEC states that under the Commission‘s accounting rules, there will be changes affecting the ratepayers in plant investment, attributable to increases in accumulated depreciation that will be recorded in AIU's reserve for accumulated depreciation over the period of the post-test year plant additions.

IIEC suggests it is important to ensure that the rates established are reflective of costs and revenues that may be expected for the period during which such rates are in place. IIEC believes the unbalanced calculation of plant investment and rate base proposed by AIU is not representative of the period rates set in this case will be in effect. According to IIEC, the proposed mismatch of February 2010 plant additions and December 2008 accumulated depreciation is one that will never exist on the books of AIU. IIEC insists that the adjustment it proposes is necessary for accurate measurement of the utility's rate base, and not just its plant additions. In IIEC's view, AIU‘s proposed pro forma adjustment by itself is an anomalous calculation that is inconsistent with test year principles and the Commission‘s test year rules.

IIEC says that in prior cases the Commission was presented with competing views of the future and the effects of its approvals. In this case, IIEC claims the Commission has hard evidence of the consequences of approval of such unbalanced pro forma adjustments. According to IIEC, there is ample expert testimony in this case from a broad range of experts showing the inconsistency of such adjustments with the Commission‘s accounting rules and conventions.

IIEC states that in ComEd's last rate case, the Commission permitted ComEd‘s rates to be set based on ComEd‘s post-test year plant addition adjustments. IIEC claims that ComEd‘s projected increase in gross plant in service was reasonably accurate. However, IIEC asserts its pro forma adjustments for plant additions, excluding accumulated depreciation reserve, substantially understated the amount of accumulated depreciation reserve on its books and records at the end of the period of its plant additions. According to IIEC, ComEd substantially overstated its net plant in service ($464 million to $521 million), equivalent to a revenue requirement effect in the range of $50 million to $60 million per year. IIEC believes that actual experience confirms the results predicted by an unbiased application of the Commission‘s accounting and test year rules. IIEC contends that to accurately match costs and revenues for the period rates are in place, if the Commission allows post-test year plant additions, it must also include adjustments to recognize the contemporaneous changes to the accumulated depreciation reserve.

According to IIEC, this record contains extensive expert testimony explaining that AIU's proposal is inconsistent with Commission accounting and depreciation rules and is not representative of the rate base that AIU will have in place when rates are in effect. IIEC argues that unreasonable costs (including, presumably, unlawful costs) can not be the basis for just and reasonable rates. While the rate base AIU uses for setting rates is increased by almost one-quarter billion dollars, IIEC complains that AIU‘s version of the matching principle allows a self-serving mismatch of investment costs through February 2010 with a static 2008 test year accumulated depreciation reserve.

IIEC states that AIU criticizes it for not proposing adjustments for every revenue requirement item that could change after the test year. IIEC responds that not every potential post-test year change is ―reasonably certain to occur” or ―known and measurable” as Section 287.40 requires. IIEC asserts that in contrast, the growth in the reserve for accumulated depreciation will occur as surely as night follows day. IIEC also argues that it is AIU's burden to prove that it has made all appropriate adjustments.

IIEC indicates that AIU also questions whether the post-test year changes in accumulated depreciation are known and measurable, pointing to a difference in the adjustment calculations of AG/CUB and IIEC. IIEC responds that AIU's witness on this issue, Mr. Fiorella, testified that he had not verified that the two amounts he compared were actually calculations of identical adjustments. IIEC also contends that AIU's argument that a dispute as to the proper quantification proves that an adjustment is not known and measurable, applies more aptly to AIU's own adjustment. IIEC says that AIU ultimately accepted an agreed, not calculated or precise, amount of "known and measurable" plant additions.

According to IIEC, AIU's contention that it may move gross plant (with minor modifications) to a post-test year date, but that offsetting elements of rate base can not be moved is essentially an argument that only post-test year increases to rate base are permitted by Section 287.40. IIEC claims that reading Section 287.40 to refer to variations of gross plant is not reasonable, when the only lawful changes affecting the ratepayers in plant investment are changes in net plant. IIEC says AIU's "increases-only" reading would bar known and measurable post-test year reductions, defeating mitigation of regulatory lag in many situations. IIEC insists that its interpretation of Section 287.40 is consistent with the Commission's accounting, depreciation, and other test year rules. IIEC claims that AIU's interpretation requires that otherwise applicable rules, conventions and procedures be abandoned to allow computation of net plant and rate base in a way not proposed or countenanced by any party in any other context.

According to IIEC, Staff frames the dispute about post-test year adjustments as one of balancing "regulatory lag" against the "matching principle." IIEC says the precise meaning of that observation is not clear. However, IIEC does not accept that any balancing of competing elements of regulatory doctrine can displace the Act's express statutory prohibition against the Commission's inclusion of excess investment in AIU's ratemaking rate base. IIEC also asserts that an unexplained, unjustified departure from the accounting and depreciation requirements codified in the Commission's rules is a violation of law that can not be excused by a balancing of regulatory issues.

IIEC believes that Staff witness Ebrey's testimony on accounting fundamentals makes it clear that AIU's proposed adjustment would make the test year data considerably less accurate and would violate test year matching requirements and the Act. IIEC agrees with Staff that any overstatement of net plant would violate the matching principle and go beyond the remedy for regulatory lag. IIEC believes that AIU's adjustment overstates net plant and rate base, departs from Commission accounting and depreciation rules, violates the test year matching principle, and results in an unlawful, excessive rate base that the Commission lacks authority to approve.

d. Staff Position

Staff did not provide written testimony on this issue; however, during cross-examination, Staff witness Ebrey provided comments regarding the mechanics of the revenue requirement and the relationships among its various components. (Tr. at 738-747, 800-803) Staff says Ms. Ebrey confirmed that as of February 2010 the amount of net plant on the AIU books would not reflect the amount of accumulated depreciation at the December 2008 level. Ms. Ebrey further stated that, for ratemaking purposes, the matching principle would require the alignment of all components of the revenue requirement including all components of rate base, cost of service, and ROR information as of a consistent date. Finally, Ms. Ebrey concluded that the net plant as proposed by AIU in this case would be higher than the net plant included in the utilities books at the end of February 2010.

According to Staff, this issue is about balancing ―regulatory lag" (the AIU argument) with the ―matching principle" (IIEC's argument). Staff says regulatory lag is the theory that rates granted in a rate proceeding will lag behind ongoing costs since costs could be expected to rise from the filing of a rate case until the final order in the rate case is issued and rates become effective. In addition, Staff states that costs could also increase after the approved rates are actually in effect. To remedy the problem with regulatory lag, Staff says pro forma adjustments are allowed in the ratemaking process to include more current costs beyond the historic test year levels. Staff avers, however, that there is a point in which the remedy for regulatory lag intentionally overstates anticipated costs at a certain point in time or during the time that rates would be in effect. In Staff's view, the balance of net plant used to set rates in this case should not be greater than the anticipated actual net plant balance in February 2010 or during the time that rates from this case are expected to be in effect. Staff believes that any overstatement of net plant would violate the matching principle and go beyond the remedy for regulatory lag.

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

According to Staff, AIU claims that the distinguishing factor in the Order in Docket Nos. 02-0798 et al. (Cons.) is that the AmerenCIPS' net plant in service was declining or static. Staff alleges that AIU omits the conclusion, as it relates to AmerenUE, in that case where net plant was not declining. Staff states that IIEC correctly calls attention to that difference in its Initial Brief when it discusses the treatment afforded AmerenUE to limit its post test year capital additions to the extent that they exceed increased accumulated depreciation. Staff asserts that even though it is undisputed that AIU‘s net plant in service has been increasing, the Commission has stated it ―might be inclined to allow post test year additions to rate base," but only to the extent that those additions exceed increases to accumulated depreciation.

e. IBEW Position

According to IBEW, the Commission should reject the additional adjustment to AIU‘s accumulated depreciation reserve suggested by AG/CUB and IIEC. IBEW states that such adjustments have been raised repeatedly in prior rate cases, and have been rejected by the Commission each time. IBEW says no new rationale or evidence has been offered that would differentiate this rate case from the four prior rate cases in which the Commission has rejected the additional adjustment.

f. Commission Conclusion

On a related issue, AIU and Staff agree that pro forma plant additions to rate base through February 2010 should be included in rate base. IIEC and AG/CUB believe that the balance of the accumulated reserve for depreciation, which is a reduction to rate base and the other component in the calculation of net plant – the major element of rate base, should reflect the February 2010 balance because AIU has included in rate base pro forma gross plant additions through that date. This proposal is supported by Staff in its Initial and Reply Briefs and opposed in the briefs of IBEW. AIU also opposes the proposal, arguing that the 2008 test year balance of the accumulated reserve for depreciation should not be revised for existing (i.e., embedded) plant.

The parties' extensive arguments regarding this issue are recited in detail above. The Commission emphasizes that it has closely reviewed the parties' positions, which are clearly articulated, as well as the cases and statutory provisions cited by the parties and fully understands both points of view.

AIU argues that increasing the reserve for accumulated depreciation to reflect the February 2010 balance is not permissible under Section 287.40 and would compromise the test year net plant in service balance. AG/CUB and IIEC, on the other hand, argue that Section 287.40 provides for a pro forma adjustment to recognize certain post-test year changes in the investment dedicated to providing service to customers and that determining that amount consistently within the limitation of Section 9-211 of the Act requires taking account of declines in rate base value over the period of recognized increases in investment. Specifically, they argue that an adjustment for post-test year changes in plant investment requires that both plant additions and the reserve for accumulated deprecation be considered in determining the actual change in the value of rate base investment and that doing so yields a net plant in service balance that is consistent with the intent of the test year rules.

The Commission has reviewed the Orders in Docket Nos. 01-0423, 02-0798 et al. (Cons.), 05-0597, 07-0241/0242 (Cons.), and 07-0566. As the parties have pointed out, prior Commission decisions are not *res judicata* and the decision here must be based upon the record in this case. United Cities Gas Co.,163 Ill. 2d at 22.

This issue has been thoroughly briefed by the parties before the Commission over the last several years, allowing the Commission greater clarity in understanding the positions presented by the individual parties and the meaning and intent of the pro forma adjustment rule. This proceeding, along with prior proceedings on this same issue, has resulted in a significant evolution of the Commission's understanding of this issue. In this particular case, the predominant weight of the evidence stands in opposition to AIU's position on the issue. The record in this case provides sound reasons for a departure from certain prior Dockets, and notably, this Commission's decisions for AIU have consistently required recognition of the accumulated depreciation on embedded plant through the date of pro forma plant additions.

AIU has proposed a 2008 historical test year, which is allowed under the Commission's rules. The Commission's rules are intended to match costs and revenues over a consistent period, i.e., the test year. One "exception" to the test year requirement that costs and revenues reflect historical test year values is the provision in Section 287.40 that allows pro forma adjustments for "known and measurable" changes to a historical test year. Among other things, Section 287.40 allows pro forma adjustments for changes in plant investment. AIU cites certain previous decisions that effectively abandon the concept of a net plant investment when there is a pro forma adjustment for post-test year plant additions.

IIEC points to evidence that distinguishes this record from the recent decisions AIU asks the Commission to follow. A fresh look at the substance of the competing proposals, aided by evidence presented for the first time in this record, demonstrates that IIEC's objections to the AIU proposal are well founded. We find two portions of the record evidence to be particularly compelling. First, the opinion of the Commission Staff's accounting expert, after delineating the mechanics of the regulatory accounting for utility rate base and reviewing the new evidence in this record, was that regulatory accounting requires the plant in service balance and the accumulated reserve for depreciation balance to be representative of the same point in time. (Tr. at 734-749, 800-803) The second evidentiary presentation is IIEC's analysis showing the result of a policy that recognizes only one part of net plant in determining rate base. That analysis validates (with empirical data) the arguments and expert testimony that any adjustment recognizing only post-test year increases will overstate a utility's actual rate base and not be representative of the period rates are in effect. We refer to the evidence showing that the actual results of the adjustment approved in a recent Commonwealth Edison case was a significantly overstated rate base, as predicted by the testimony and arguments the Commission rejected in that case. We find this evidence alone to be a sufficient reason in this case to require AIU to reflect the balance of the accumulated reserve for depreciation as of February 2010 in its rate base, because AIU has included pro forma plant additions in its rate base as of February 2010.

In addition to the evidence discussed above, the Commission believes there are other reasons to make this adjustment. The Commission understands AIU's point of view with respect to the prior decisions on which it relied; however, such a pro forma adjustment is not consistent with any reading of the Commission's test year rules that is also consistent with the limitations of Section 9-211 of the Act. Section 9-211 essentially requires the Commission to ensure that a utility's approved rate base does not exceed the investment value the utility actually uses to provide service. The measure of the amount of investment so dedicated must account for both increases and decreases (over a consistent period) at any point in time. Under Section 9-211, contemporaneous increases and decreases to rate base are not severable items that can be given disparate treatments. They are opposing sides of a coin, the utility's plant in service and net plant. Accordingly, the Commission approves IIEC's correction to AIU's adjustment for plant additions through February 2010 to account for contemporaneous additions to the reserve for accumulated depreciation over that same period. The decisions cited by AIU did not address the effect of Section 9-211 in this context.

While the rule, as interpreted here, may allow for a situation where a utility's gross plant increase would be outpaced by its additional accumulated depreciation, a) this result occurs because it reflects the true reality of a utility's financial picture for the pro forma period, and b) in anticipation of such a result, the utility may elect not to seek pro forma adjustments. Thus, even as interpreted here, the rule should still only operate to increase rate base—the utility can choose to seek pro forma adjustments when increases in gross plant outpace depreciation, and elect not to seek them when they do not. But in all instances, the rule operates to give the Commission an accurate and balanced snapshot of the utility's financial picture for ratemaking purposes.

However, a reading of the rule which excludes accumulated depreciation for the pro forma period incents the utility to always seek upward pro forma adjustments regardless of any decline in actual net plant—and for an amount that ignores accompanying depreciation accumulating over the same period. This interpretation results in consistently and unavoidably inflated rate base and an inescapably inaccurate picture of the utility's finances. This reading is also plainly inconsistent with the Commission's treatment of plant investment should the utility adopt a future test year under Section 287.20(b), plainly inconsistent with basic matching principles, and inconsistent with the approach taken in at least six other states.

To avoid confusion respecting proposals in future rate cases, the Commission finds that if a utility has recovered in rates the cost of an asset through depreciation expense, the associated amount of accumulated depreciation should be deducted from rate base.

3. Pana East Substation

a. AIU Position

AIU asserts that the relocation of the Pana East Substation allowed AmerenCIPS to remediate coal tar contamination at the site in the most practical, cost-effective manner possible. AIU claims that relocating the substation also ensured that AmerenCIPS could continue to provide service to its electric customers during the remediation. In addition, during the course of the relocation, AIU says AmerenCIPS refurbished and upgraded the substation to further improve the reliability of service and enhance service for present as well as future customers. AIU believes these costs were prudent and necessary and should be included in AmerenCIPS' electric rate base.

AIU indicates that Staff proposes a rate base adjustment to exclude all capital costs, roughly $2 million, incurred by AmerenCIPS in relocating the substation. Staff proposes this rate base adjustment despite the fact that it does not dispute that these costs were both necessary and prudently incurred. AIU also understands that Staff does not contest that the relocated substation is used and useful in providing electric service.

Although Staff objects to allocating 100% of the substation relocation costs to AmerenCIPS' electric delivery service customers, AIU observes that Staff has not proposed any specific alternative allocation. In the absence of any evidence from Staff proving that the relocation costs should be allocated in any manner other than 100% to electric distribution customers, AIU contends that Staff has not justified allocating any portion of these costs to AmerenCIPS' gas ratepayers, transmission customers, or shareholders. AIU claims that Staff admits that shareholders would normally not absorb these costs. AIU complains that Staff simply proposes to exclude from rate base all capital expenditures for this project because Staff feels that electric distribution customers should pay some lesser, undefined percentage of the costs.

AIU acknowledges Staff's argument that AmerenCIPS' electric distribution ratepayers should pay less than 100% of the substation relocation costs because the cause for the costs is unrelated to the provision of electric service. According to AIU, Staff theorizes that if the contamination had originated from equipment in the substation, or was in some other way caused by the provision of electricity to customers, then it would be logical to allocate 100% of the substation relocation costs to facilitate clean-up to electric ratepayers. In response, AIU insists that the —cause" for the substation relocation simply does not impact the appropriate allocation and recovery of these costs. AIU argues that it is appropriate to include in a utility's rate base the cost to repair or relocate distribution infrastructure, assuming it was prudent and necessary to incur those costs to maintain adequate, reliable service.

AIU states that any number of factors unanticipated and beyond the utility's control could require a utility to repair or relocate its distribution plant. AIU notes that Staff recognizes that an extreme weather event, such a tornado or inland hurricane, could require a utility to repair damaged poles or wires. AIU adds that Staff also acknowledges that an unexpected changing environmental condition, such as the emergence of mine subsidence or a flood plain, could require a utility to relocate existing facilities. AIU asserts that Staff concedes that in these instances it would be appropriate to charge electric ratepayers for the costs to repair and relocate infrastructure if such actions were necessary to maintain adequate and reliable service. AIU maintains that the relocation of the Pana East Substation not only was the least cost option and safest way to remediate the contamination, but it also presented the least risk of a disruption of service to AmerenCIPS' customers.

AIU indicates that in 1956 and 1957, when the Pana East Substation was constructed, AmerenCIPS was not required to remove any coal tar present at the site. With changes to environmental laws and regulations since the 1950s, however, AIU says AmerenCIPS now is required to clean up the coal tar contamination underneath the substation. Removal of the contamination without disrupting service, AIU contends, dictated the need to relocate the substation. AIU insists that all other options to remediate the site without relocating the substation were rejected as impractical, unsafe, cost-prohibitive, or too risky to the adequacy and reliability of AmerenCIPS' service. AIU says that by relocating the substation, AmerenCIPS was able to clean up the site in a practical and safe manner and at a reasonable cost. AIU adds that AmerenCIPS took advantage of the need to relocate the substation to expand and modernize the facility, improving the location, design, equipment, and automation of the fifty-year-old substation. No one argues that AmerenCIPS should have cleaned up the coal tar in the 1950s or built the substation at a different location with the expectation that at some point in the future it might be required to clean up the coal tar. AIU avers that AmerenCIPS should not be denied recovery of these relocation costs simply because it is now obligated to clean up this contamination 50 years after the original substation was constructed.

Staff suggests that AmerenCIPS would not charge its electric distribution ratepayers 100% of the costs to relocate a customer's house if the property had contamination that originated from an AmerenCIPS' former manufactured gas plant. Staff asserts that there is no difference between the hypothetical costs associated with relocating the customer's house to facilitate cleanup and the actual costs associated with relocating the Pana East Substation. In response, AIU argues that the customer house in Staff's analogy was not used and useful in providing service. AIU also asserts that the remediation of the customer's property did not impair or threaten the adequacy and reliability of service. AIU adds that the relocated customer house did not provide a benefit to electric ratepayers.

Staff also claims that it would be inappropriate for AmerenCIPS to recover from electric ratepayers 100% of the relocation costs because the substation was used and useful at its former location. AIU counters that AmerenCIPS did not choose to relocate the substation just for the sake of doing so; its hand was forced by its obligation to remove the contaminated soil directly under the substation. AIU claims no other alternatives were feasible or practicable given the regulatory requirements to remove the coal tar and the need to maintain service.

According to AIU, Staff further claims that it remains a mystery why AmerenCIPS is unwilling to allocate its relocation costs in a fashion similar to the allocation of the coal tar remediation costs. AIU believes it is more mysterious why Staff refuses to propose an alternative to AIU's proposed allocation. If Staff wants AIU to allocate the relocation costs in the same manner as remediation costs, AIU contends it should just say so. AIU maintains that Staff's comparison of relocation costs to remediation costs, which Staff recognizes are properly borne entirely by ratepayers, suggests that Staff believes that relocation costs are in fact fully recoverable through rates. AIU complains that Staff, however, proposes in these rate cases to exclude these costs in their entirety.

AIU asserts that the allocation of coal tar remediation costs is not relevant to determining the proper allocation of the capital costs to relocate and rebuild the substation. AIU says the basis for allocating remediation costs between AmerenCIPS' electric and gas customers are the formulas set forth in Riders EEA and GEA. AIU claims the allocation formulas for AmerenCIPS' remediation costs, which were approved by the Commission, neither control nor are determinative of the proper allocation of AmerenCIPS' relocation costs. AIU insists that the basis for allocating capital costs is the need for the expenditure and the resulting benefit.

b. Staff Position

Staff disagrees with AmerenCIPS' proposal to charge electric ratepayers 100% of the cost to relocate the Pana East Substation and the distribution and transmission lines entering and leaving the substation as part of a coal tar remediation project. The amount in dispute equates to approximately $2 million. Staff understands that the Environmental Protection Act, 415 ILCS 5/1 et seq., assigns the cost liability of contamination clean-up to the causer of the contamination. According to Staff, Section 58.9 of the Environmental Protection Act assigns liability for the cost of the clean-up of contamination to the party or entity that caused the release, not to the party or entity that owns the property that was contaminated. Staff states that AmerenCIPS' Pana East Substation did not cause or release the contamination, nor did AmerenCIPS' electric ratepayers. Staff believes it would be inappropriate for AmerenCIPS to recover from electric ratepayers 100% of its costs for the relocation, which occurred to facilitate the coal tar contamination cleanup.

Staff suggests that if AmerenCIPS needed to relocate a customer's home for contamination clean-up, AmerenCIPS would not charge the customer, or for that matter its electric ratepayers, all of the relocation costs. Staff asserts that AmerenCIPS would instead appropriately allocate its costs for the relocation of the customer's home to its various lines of business, including its electric utility. Staff says no single line of business would pay 100% of the relocation cost. In Staff's view, costs associated with the relocation of the Pana East Substation should be allocated to AmerenCIPS' various lines of business, since the relocation occurred to facilitate contamination cleanup.

Staff indicates that AIU argues that Staff's hypothetical scenario involving relocation of a customer‘s house is dissimilar to relocation of the Pana East Substation, since the relocation of the substation was required in order to provide adequate and reliable electric service to customers during AmerenCIPS‘ clean-up activities, whereas a customer‘s relocated house would not be used and useful in the provision of electric service. In Staff's view, whether or not the newly relocated home or the newly relocated substation is used and useful in the provision of electricity should not be the only fact considered when deciding who should pay for the relocation. Staff says its position is not based upon whether the substation at its new location is used and useful. Staff's position is based upon the fact that AmerenCIPS‘ Pana East Substation was used and useful at its former location, and was providing adequate electric service to customers at that former location.

Staff asserts that if a third party were to request that AmerenCIPS relocate existing electric distribution facilities for which AmerenCIPS had adequate property rights, AmerenCIPS would require the requesting party to pay the entire relocation cost. Staff agrees with AmerenCIPS‘ policy that the third party, rather than electric ratepayers, should pay relocation costs when the utility‘s facilities are adequate and used and useful at the original location, and a relocation happens because the third party requested or needed the relocation. Staff suggests a similar situation occurred at the Pana East Substation. Staff says AmerenCIPS relocated its facilities associated with the Pana East Substation that were adequately providing service to its electric customers. Staff contends that the contaminated soil beneath the former Pana East Substation site did not conflict with this provision of electricity, was in no way caused by the substation, and if left in the ground, would not have affected the ability of the substation to provide adequate and reliable service to AmerenCIPS‘ customers in the future.

Staff does not object, generally, to AmerenCIPS‘ recovery of the relocation costs. But Staff believes that it would be more reasonable for AmerenCIPS‘ shareholders to bear some of the costs. Staff denies, however, that it has any obligation to provide an alternative allocation proposal. Staff states that this is AmerenCIPS‘ electric rate case, and AmerenCIPS should be able to justify its own additions to electric distribution plant. Staff also denies that AIU ever asked it to provide an alternative allocation and calls AIU‘s accusation that Staff refused to propose an alternative allocation troubling and disingenuous. Staff states that rather than justifying AmerenCIPS‘ proposed 100% allocation of relocation costs to electric ratepayers, which Staff requested it do, AIU elected to wait until the evidentiary hearing, where it attempted to shift the burden of establishing an appropriate cost allocation for the purposes of AmerenCIPS‘ rate recovery to Staff. Staff witness Rockrohr testifies that he would consider modifying his recommendation if AIU provided information or evidence to fully explain and justify its proposed 100% allocation. Rather than providing necessary information to support its own proposal, or proposing an alternative allocation, Staff claims AIU simply accused Staff of not suggesting an alternative cost allocation.

If the Commission determines that AmerenCIPS should recover its costs for relocating the Pana East Substation, but agrees with Staff that 100% allocation of costs to electric ratepayers is not appropriate, Staff suggests that the Commission may wish to consider an allocation that closely matches the allocation of the clean-up costs recovered through AmerenCIPS‘ environmental riders (Rider EEA and Rider GEA).

Staff acknowledges a concern raised by IBEW in its Initial Brief relating to possible job losses if the Commission decides not to allow AmerenCIPS to recover the relocation costs. IBEW expressed concern that if AIU fails to recover its relocation costs, it might reduce spending in other areas, such as O&M. Though it does not think it would be a good idea to do so, Staff suggests that AIU could decide to reduce its maintenance and operations expenditures for any number of reasons, independent of the Commission‘s decision regarding this substation relocation issue. While potential job loss might be a legitimate concern, Staff does not believe the Commission should base its decision upon this concern.

c. IBEW Position

IBEW argues that relocating the substation to facilitate the remediation was the least costly and most reliable solution available to comply with AIU's obligation to remediate the contamination while maintaining service to utility customers. IBEW says that other options such as undermining the substation while it was operating or utilizing additional portable substations would have been more costly and could have negatively impacted reliability. Additionally, IBEW claims the new Pana East Substation incorporates a number of improvements that will help maintain reliability in the future. According to IBEW, the labor and materials costs to relocate the Pana East Substation, which were incurred to perform required remediation and maintain service, should be recoverable through base rates.

IBEW is also concerned that although the work on the Pana East Substation has already been completed, failure to allow recovery of costs for the project may lead AIU to reduce spending in other areas, such as O&M expenses. IBEW says this could result in less preventative maintenance work and tree trimming, and fewer workers available to restore service during storms. IBEW claims the resulting job losses would also have negative economic effects in Illinois.

d. Commission Conclusion

AIU proposes to include in AmerenCIPS' electric rate base all of the capital costs associated with relocating the Pana East Substation and the distribution and transmission lines entering and leaving the substation. Staff has proposed an adjustment to AmerenCIPS' electric rate base to remove all of the approximately $2 million of capital costs associated with the project. If the Commission determines that AmerenCIPS should be allowed to recover the relocation costs from ratepayers, Staff suggests that the Commission consider an allocation that closely matches the allocation of the clean-up costs recovered through AmerenCIPS‘ environmental riders (Rider EEA and Rider GEA).

Having considered the arguments, the Commission does not believe that the record supports the suggestion that AIU shareholders should bear the costs associated with relocating the Pana East Substation. There has been no overriding policy or legal concerns raised that would justify such a decision. Staff's proposal to reduce AmerenCIPS' electric rate base by approximately $2 million effectively allocates 100% of the costs to AIU shareholders, a result that the Commission finds unreasonable and rejects.

With regard to any alternative allocation, the Commission notes that this is not simply an AmerenCIPS' electric rate case. These consolidated proceeding consist of both an electric and gas rate case for AmerenCIPS, as well as for AmerenCILCO and AmerenIP. Any party was free to suggest and support an allocation that included cost recovery from electric and gas customers (as well as shareholders). While Staff suggests as a fall back position that the Commission allocate the relocation costs in a manner consistent with AmerenCIPS' environmental riders, Staff has not sufficiently demonstrated why gas customers should bear any such costs. Nor is it clear how Staff would have the Commission implement its suggestion. The only viable alternative in the record is AIU's recommendation to include 100% of the costs associated with the Pana East Substation in AmerenCIPS' electric rate base, which the Commission adopts.

4. Hillsboro Storage Field

a. AIU Position

In 1993, IP expanded its Hillsboro Storage Field ("Hillsboro"). The Commission approved the expansion and concluded that Hillsboro would provide substantial net economic and other benefits to IP‘s customers and it should be considered used and useful when placed into operation. IP intended the expansion to increase the field‘s total storage and peak day storage withdrawal capability. IP estimated that after expansion, the storage field would contain 21.7 Billion cubic feet (―Bcf”) gas-in-place, reflecting 7.6 Bcf inventory gas and 14.1 Bcf base gas.

AIU states that since the 1993 estimate, however, with the exception of the 1993-94 season, Hillsboro has not operated at or near 7.6 Bcf. AIU indicates that using newly-available technology to update its understanding of Hillsboro and its capacity, AmerenIP has determined that geological conditions at Hillsboro likely prevent the field from operating at design capacity. AIU claims Staff fails to consider this new information, which was identified by more advanced computer modeling than what was previously available. AIU states that based on this new information, AmerenIP deems it prudent to cycle the field at 6.4 Bcf, rather than the 1993-estimated design capacity of 7.6 Bcf. Staff agrees Hillsboro should be cycled at 6.4 Bcf, but claims that Hillsboro is not 100% used and useful because it is not currently cycling at 1993 estimated levels.

According to AIU, Staff calculates Hillsboro is 96.01% used and useful and proposes a used and useful disallowance.

AIU believes Staff's recommended used and useful disallowance is flawed and must be rejected for four reasons: (1) Staff incorrectly relies on the 1993 design capacity estimate of Hillsboro and does not recognize the importance of new information, based on previously unavailable and more advanced computer modeling, regarding Hillsboro's geology; (2) Staff concedes that Hillsboro should cycle 6.4 Bcf for the next several years; (3) Staff overlooks the fact that Hillsboro substantially benefits customers; and (4) Staff wrongly connects its used and useful adjustment to past operational concerns at Hillsboro. Even if the Staff's proposed disallowance was not flawed for these reasons, AIU argues that the Commission should not impose a disallowance where Staff's calculation of the field's used and usefulness is so near 100%.

In Illinois, 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. In determining whether a facility is used and useful, AIU says the Commission considers the extent to which a plant is needed to meet the utility's projected demand and whether the plant provides net economic benefits to ratepayers.

According to AIU, the Commission recognizes that capacities estimated during the design and construction phases may differ from actual operational capacity, and thus, has rejected reliance on design capacity in determining used and usefulness. AIU claims that where a utility assigned a —nominal” capacity during design and construction of a plant as an approximate capability value, the Commission stated —it was not possible to determine precisely what the net output of the plant would be during its design and construction states, until it was completed, placed in service and tested.” (AIU Initial Brief at 32-33, citing Docket No. 89-0276, Order at 161-62) According to AIU, use of a —nominal” value for projected capability during design and construction of the plant was not a basis on which to establish the used and usefulness of a plant. Likewise, AIU argues that where capacity is restricted or not available due to physical constraints, such capacity should not be included in a plant's total effective capacity for purposes of determining used and usefulness.

To demonstrate that Hillsboro is not currently operating in —the same manner” as was originally predicted, Staff cites the Commission's 1992 order granting IP a certificate for Hillsboro (Docket No. 91-0499) before Hillsboro's expansion was complete. According to AIU, Staff essentially faults AmerenIP because Hillsboro has not operated at the projected levels since expansion. AIU contends, however, that it is Staff's reliance on design estimates of capacity that is faulty. Despite the fact that IP predicted a design cycling capacity of 7.6 Bcf in 1993 for Hillsboro, AIU claims the field's actual operating conditions are inconsistent with that design capacity. AIU says Hillsboro has not operated at 7.6 Bcf since 1993 and AmerenIP recently has been able to identify physical, capacity-limiting characteristics of the Hillsboro field by applying new technology – not yet developed in 1993 – and conducting a detailed study of Hillsboro (the —Hillsboro Study”).

AIU states that the Hillsboro Study employed several improved and independent engineering methods, including a reservoir simulation study and a hysteresis curve evaluation.[7] AIU asserts that with the use of these new, more advanced technologies, the Hillsboro Study identified a geological condition by which gas migrates to a less accessible region of the field. AIU says significant volumes of gas migrate from the St. Peter formation, which is located near the well bore that cycles gas from the field, into the Joachim cap rock porosity, which is not accessible to that bore. AIU claims the porosity of the Joachim formation traps the gas, causing a shortfall of gas to be cycled. According to AIU, this materially affects the field‘s performance relative to its design capacity. AIU says while the 1993 reservoir analysis expected the entire 21.7 Bcf of gas injected into the reservoir at the end of expansion to exist in the St. Peter formation, the Hillsboro Study revealed that approximately 3.5 Bcf of gas has since migrated from the St. Peter formation into the Joachim cap rock porosity. AIU avers that the Hillsboro Study indicated the St. Peter formation cycles only 5.8 Bcf of working gas, while the Joachim porosity cycles 0.6 Bcf. In AIU's view, the Hillsboro Study demonstrated that the best current estimate of working gas capacity is 6.4 Bcf. AIU contends that the volume currently and prudently cycled at Hillsboro, and not the estimated volume, should determine the used and usefulness of the field. AIU says the Commission has determined that —the used and useful calculation should be based on the Company‘s existing capacity configuration,” which the Commission terms —actual capacity.” (AIU Initial Brief at 34-35, citing Docket Nos. 87-0427 et al. at 90)

AIU also argues that modifying the amount of working gas cycled is not unusual. AIU states that underground storage reservoirs are very complex/heterogeneous geological formations, and as a result, these reservoirs are difficult to fully understand because there are multiple variables that can change and many variables that can not be discretely measured but must be interpreted. AIU claims volumes are commonly adjusted based on the field‘s actual operating experience and recently updated information. AIU claims that other gas utilities have similarly adjusted working volumes without a disallowance or other penalty. According to AIU, in Docket No. 90-0127, the Commission approved a working gas inventory adjustment but did not make a used and useful disallowance. AIU also says that in Docket Nos. 07-0585 et al. (Cons.), a working gas inventory adjustment was made at Sciota field without a used and useful disallowance. AIU states that in that case, like here, studies indicated the need to adjust working and base gas.

AIU says Staff asserts that AmerenIP can not make any changes to the Hillsboro specifications until it has operated the field in a certain manner because it still does not know what those specifications are, even though the field expansion took place 16 years ago. AIU claims this mischaracterizes AmerenIP‘s position on inventory revisions

[7] A hysteresis curve is a plot of the gas pressure in the storage field versus the field inventory, which can be used to verify the inventory within the field and to monitor the underground storage reservoir's performance.

at Hillsboro. AIU insists that the Hillsboro Study does not state that AmerenIP needs to cycle the field in a consistent manner or can not make changes to the field specifications. Rather, AIU claims the Hillsboro Study recommends that 6.4 Bcf of gas be cycled from the field for the next several years and that verification studies be performed. AIU says the Hillsboro Study also asserts that the annual cycling of 6.4 Bcf will help the reservoir stabilize further, increasing the accuracy and validity of the reservoir engineering studies.

AIU says AmerenIP plans to consistently operate the field at 6.4 Bcf over the next few years to conduct reservoir engineering studies. AIU states that Staff does not disagree with AmerenIP‘s logic on seeking to operate the field at 6.4 Bcf and agrees that maintaining the field at a consistent level will allow AmerenIP to better determine the operating characteristics of the field. According to AIU, Staff acknowledges that Hillsboro may not be able to operate at its design capacity.

AIU indicates that IP invested over $154 million to expand Hillsboro in 1993. AIU insists that this investment benefits customers by allowing AmerenIP to purchase and inject gas when less costly in the summer and withdrawing it in winter; it also increases peak day deliverability. AIU claims customers‘ savings for the first year were estimated at $14,596,500, and says Staff does not dispute that these benefits have been, and continue to be, realized. Since it is unclear whether Hillsboro is able to operate at 7.6 Bcf, AIU contends it is unclear whether extra ratepayer benefits are achievable. Until operational parameters are further defined, AIU asserts it is imprudent to risk the additional 1.2 Bcf of gas costs.

AIU understands that Staff's used and useful proposal relates to past operational issues at Hillsboro. According to AIU, Staff argues that due to inventory corrections at Hillsboro, AmerenIP could not conduct inventory verification studies and now must operate the field consistently to determine its current operating parameters. AIU argues that regardless of what transpired in the past, AmerenIP could only now identify the geological limitations to the field‘s capacity because the necessary technology was not previously available. AIU says Staff agrees that information now known differs from the facts of Docket No. 04-0476, and that AmerenIP addressed prior events that impacted Hillsboro‘s inventory volumes. AIU relates that in Docket No. 04-0476, Staff considered volume histories to reduce withdrawal volumes, but here, Staff considers working volumes by relying on scheduled withdrawal volumes. Also, previously, AIU indicates that metering errors caused volumes reductions, while here, working volumes are reduced at Hillsboro because of geological conditions.

AIU believes the Commission should reject Staff's suggestion for a ruling to ensure AmerenIP is aware of the Commission‘s concerns with the operation of Hillsboro. AmerenIP believes such a ruling would be improperly punitive. AmerenIP encourages the Commission to rule on the evidence presented to determine whether the costs associated with Hillsboro were prudently incurred. (AIU Initial Brief at 39)

AIU contends that a disallowance in such a close case is inappropriate, especially given that gas storage operations can be unpredictable. If a field is prudently operated based on the information currently available, AmerenIP maintains that a disallowance is not appropriate when new information suggests the utility should change its operations. According to AIU, customers still have benefited far more by having the Hillsboro asset than not having the asset. Given the prudent operation of Hillsboro, and benefits enjoyed by customers, AmerenIP asserts that a disallowance based on a 96.01% used and useful calculation is poor policy. AIU claims Hillsboro is operating to meet current customer demand and provides net economic benefits to ratepayers and believes it is 100% used and useful.

b. Staff Position

Staff asserts that Hillsboro is not operating in the same manner that it was when IP expanded the field and placed the costs associated with the expansion into its base rates in Docket No. 93-0183. Given the manner in which AmerenIP is currently operating Hillsboro, Staff claims it is no longer 100% used and useful at providing service to AmerenIP's customers. Staff calculates a used and useful percentage for the field to equal 96.01% and recommends the Commission use this value to set the rates in this proceeding. Staff asserts further that AIU failed to maintain Hillsboro in an appropriate manner. Staff believes ratepayers should not be required to continue paying for Hillsboro as if it were operating at 100% used and useful when, in reality, Hillsboro is not operating in that fashion.

Staff relates further that the Commission previously adopted a used and useful adjustment regarding Hillsboro in Docket No. 04-0476. Staff reports that AmerenIP appealed the Commission's finding that Hillsboro was only 53.44% used and useful. The appellate court affirmed the Commission's decision on October 2, 2006.[8] Staff claims its methodology in the instant proceeding followed the same methodology accepted by the Commission and confirmed by the appellate court. Specifically, Staff's used and useful calculation was based on splitting the value of Hillsboro into two components – peak day capacity and seasonal price variation. Staff then determined that the value of Hillsboro came 79.70% from peak day capacity and 20.30% from seasonal gas costs savings. Staff used these values as allocation percentages within the used and useful calculation. Next, Staff used Hillsboro's three-year historical average, years 2006 through 2008, of the amount of peak day capacity and working gas inventory available to ratepayers to determine the used and useful percentages for the field. Staff says this calculation provided a used and useful amount of 96.01%. According to Staff, AmerenIP has not disputed the mechanics of Staff's used and useful calculation, but has disputed the need to make any used and useful disallowance at all.

Staff reports that in Docket No. 91-0499, IP received a certificate of public convenience and necessity for its expansion of Hillsboro. In Docket No. 93-0183, Staff says IP also received Commission authority to expand Hillsboro and to recover the cost of that expansion through its rates. As a result of these Orders, Staff states that IP, with

[8] The decision was issued as an unpublished Rule 23 Order.

Commission approval, conducted an extensive expansion of Hillsboro to increase its peak day capability (now rated at 125,000 Mcf/day), and the volume of inventory maintained in the field (7.6 Bcf of inventory gas and 14.1 Bcf of base gas). Further, Staff indicates that the Commission found the field to be 100% used and useful based upon those values in Docket No. 93-0183.

Staff compared the current operation of the storage field to post-expansion levels at Hillsboro. Staff states that Hillsboro has not operated near the levels discussed in Docket Nos. 91-0499 and 93-0183 since IP placed it into service for the winter season of 1993-1994. Staff claims that when the field does not operate according to its design parameters, AmerenIP passes any additional gas costs it incurs to make up for the problems at Hillsboro to ratepayers through its PGA rates. Staff argues that AmerenIP‘s customers have paid twice for some of the Hillsboro capacity. Staff asserts that this occurs because AmerenIP charges its customers base rates that include the cost of the Hillsboro expansion and charges these same customers for any additional gas cost caused by the Hillsboro facility de-rating that are included in the PGA rates.

AmerenIP notes that in its more recent rate case, Docket Nos. 07-0585 et al. (Cons.), that Hillsboro was fully operational. AmerenIP also provided an analysis in that case that showed the volumes withdrawn from Hillsboro, after accounting for the weather as well as other extraneous events. According to this analysis, Staff says the gas withdrawal levels for Hillsboro were at or near the expected withdrawal levels. According to Staff, AmerenIP indicates that various extraneous events impacted AmerenIP‘s ability to fully withdraw gas from Hillsboro in the recent 2006/2007 winter season. AmerenIP states that, excluding the temperatures experienced, it had addressed each of these events.

Staff asserts further that it does not appear that AmerenIP has resolved all of the problems at Hillsboro. Staff observes that Hillsboro has actually started to see a reduction in the seasonal withdrawal quantity. Staff claims that Hillsboro‘s withdrawal volumes are not back to the full operating capacity of the field, namely, a seasonal withdrawal quantity of 7.6 Bcf. According to Staff, winter season heating degree days ("HDD") actually experienced the last few years should not have caused any limiting factors for the withdrawals from Hillsboro. Staff asserts that while the last several winter seasons have been significantly colder than normal, AmerenIP was only able to withdraw about 6.6 Bcf in the 2007/2008 winter season and only 5.8 Bcf in the 2008/2009 winter season. Staff states that one would expect the volume of gas withdrawn from storage to be higher in a colder than normal winter season than a warmer than normal winter season. Staff says that although AmerenIP experienced the highest number of HDD during the most recent winter season, 2008-2009, the gas withdrawn from Hillsboro during the most recent winter season was the lowest volume in the last four years.

AmerenIP plans to operate Hillsboro at an annual withdrawal rating of 6.4 Bcf versus the 7.6 Bcf rated capacity and indicated its Hillsboro Study supported this withdrawal level. While it does not disagree with AmerenIP‘s reasoning for operating

Hillsboro in this manner, Staff asserts the reason for operating the field at the lower withdrawal rating is partially due to the prior measurement errors that AmerenIP experienced at the storage field. Staff contends that these measurement errors have necessitated further study of the field. Staff insists that the prior years of changing inventory volumes and the uncertainty which results from the multiple metering corrections have created a situation where AmerenIP needs additional time to study Hillsboro. Staff says the optimal method for conducting these studies is to operate the field at a consistent level.

Not only does AmerenIP need consistent operation of Hillsboro to allow the use of the hysteresis curve analysis, Staff says the past inventory problems also impact the use of the simulation model that AmerenIP relies on to review its field. When reviewing storage fields, Staff indicates the volume of gas within the field is an important assumption for the model. Staff states that AmerenIP's prior measurement errors at the storage field caused uncertainty in the total inventory value of the field. Staff believes the constant operation of the storage field will also allow better analysis through the simulation model in the future.

Staff claims AmerenIP does not have a good handle on all of these facets of Hillsboro's operation at this time. Staff states that the recent Hillsboro Study provides additional insight into the operation of the Hillsboro storage field, but it also identified additional areas to investigate. Staff complains that 16 years after the expansion of the field, AmerenIP still does not know why the Hillsboro storage field operates at its current levels or even if the original 7.6 Bcf rating is appropriate. Staff contends that this problem should not be borne by ratepayers. According to Staff, it is a function of prior problems that AmerenIP failed to identify in a timely fashion whose impact is still being felt today.

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

AIU indicates that in Docket No. 89-0276, the Commission rejected reliance on design capacity in determining used and usefulness and that the Commission stated that it was not possible to determine precisely what the net output of the plant would be during its design and construction stages, until it was completed, placed in service, and tested. Staff indicates that the Commission's discussion within the Order determined the appropriate in-service capacity rating to assign the Clinton nuclear power plant in order to determine the appropriate percentage of the plant to place into rates. Staff believes AIU's application of this Order to this proceeding is incorrect.

Staff states that during the first winter of operation, 1993-1994, Hillsboro operated at its expected levels, or in other words, AIU tested the capability of the field. Staff argues that AIU achieved the original operating specifications: a peak day of 125,000 Mcf/day and seasonal capacity of 7.6 Bcf. In Staff's view, the Commission‘s Order in Docket No. 89-0276 does not require any deviation from the values Staff assigned to Hillsboro in its used and useful calculation for the field in the instant proceeding.

Staff indicates that AIU also references the Commission Order from Docket Nos. 87-0427, et al. AIU indicates that this Order noted that where capacity is restricted or not available due to physical constraint, such capacity should not be included in a plant‘s total effective capacity for purposes of determining used and usefulness. Staff says AIU also states that the Commission indicated that the used and useful calculation should be based on the utility‘s existing capacity configuration. Staff indicates that AIU concluded that it is not appropriate to base a used and useful calculation on design, as opposed to actual capacity, in this proceeding. AIU instead claims that the Commission‘s used and useful assessment should consider the current effective capacity of Hillsboro.

Staff says the Order in Docket Nos. 87-0427 et al. discussed effective capacity and capacity configuration in the context of whether to include the capacity from retired electrical peaking units or capacity associated with summer limitations on power production plants in the used and useful calculation. Staff states that the used and useful determination of an electric power production plant compares the utility‘s peak demand, adds a reserve margin, subtracts out total capacity without the plant in question, and then reviews what percentage of the plant is needed to meet customers‘ demands. Staff asserts that there is no corresponding topic in the instant proceeding. Staff states that AIU placed Hillsboro in service in 1993, which Staff believes is the time for Staff and the Commission to review what other resources AIU had in place to determine if AIU needed Hillsboro and if it was used and useful. According to Staff, the issue in the instant proceeding, namely AIU‘s inability to operate Hillsboro at its full capacity, is distinguishable from AIU‘s reference to Docket Nos. 87-0427 et al.

AIU also claims that other companies have adjusted working volumes within their storage fields in the past without penalty. AIU then claims that the instant proceeding is the same as these earlier cases because studies indicate the need to adjust working and base gas. Staff asserts that AIU is not proposing to alter Hillsboro‘s working or base gas inventory levels and has chosen to operate the storage field in a consistent manner to determine the operating parameters of the storage field. Staff claims these facts distinguish the instant proceeding from those referenced by AIU.

Because the Commission approved Hillsboro as operating at the higher capacity, Staff believes that Hillsboro would provide even more savings to customers if AIU operated the field at its expected levels. Staff also claims that AIU made this exact same argument in Docket No. 04-0476; however, Staff says the Commission rejected AIU‘s reasoning and determined that a used and useful adjustment was appropriate.

Regarding AIU‘s claim that the technology only now exists to identify the problem, Staff says AIU did not make claim this until the filing of its surrebuttal testimony. Additionally, Staff claims the underlying problem relates to the migration of gas into the Joachim layer of somewhat permeable cap rock. However, Staff contends that this migration has occurred since AIU started storing gas in Hillsboro in 1972. Staff argues that when AIU expanded the field in 1993, it likely exposed additional areas for gas to migrate. Staff states that the initial expansion took place over 15 years ago and migration was on-going during this time period. While Staff does not dispute that some migration is likely still taking place, Staff believes AIU does not have a good handle on all of these facets of Hillsboro‘s operation at this time. Staff believes this occurred, in part, due to the past problems AIU has had with metering errors causing inventory reductions at the field and has kept AIU from being able to properly review or operate the field in the past.

AIU claims that in Docket No. 04-0476, Staff relied on historical withdrawal volumes from the Hillsboro storage field, but in the instant proceeding is placing reliance on the scheduled withdrawal volumes. Staff disputes this claim. Staff insists it based its used and useful calculation on the historical withdrawal volumes from Hillsboro in a manner consistent with the approach used in Docket No. 04-0476.

c. AG/CUB Position

AG/CUB believes that it is not equitable for ratepayers to continue paying for Hillsboro as if it were operating at 100% used and useful, when in reality it is not and has not been so operating for some time. AG/CUB agrees with Staff that the Commission should find only 96.01% of Hillsboro used and useful. AG/CUB points out that Staff listed prior AIU cases where it raised concerns about the manner in which IP operated Hillsboro and recommended disallowance. AG/CUB notes that AIU attempts to distinguish Docket No. 04-0476 from the instant proceeding by arguing that the reduction in volumes in Docket No. 04-0476 were due to metering errors, while the reduction in the immediate proceeding is due to geological conditions inherent to Hillsboro. AG/CUB counters that AmerenIP does not know why Hillsboro operates at its current levels, or even if the original 7.6 Bcf rating is appropriate. AG/CUB believes ratepayers should not bear this problem.

d. Commission Conclusion

Staff recommends that the Commission find Hillsboro is 96.01% used and useful, and that an adjustment to AmerenIP's rate base should be made to recognize this finding. AIU disagrees, among other things arguing that Staff incorrectly relies on the 1993 design capacity estimate of Hillsboro and does not recognize the importance of new information. AIU also claims that Staff concedes that Hillsboro should cycle 6.4 Bcf for the next several years. AIU also contends that Staff overlooks the fact that Hillsboro substantially benefits customers. AIU asserts that Staff wrongly connects its used and useful adjustment to past operational concerns at Hillsboro. Finally, AIU argues that the

Commission should not impose a disallowance where Staff's calculation of the field's used and usefulness is so near 100%.

As an initial matter, the Commission observes that AIU argues that its planned operation of Hillsboro is prudent. In this proceeding, no party takes issue with the prudency of AIU's actions and the Commission simply notes that investments must be both prudent and used and useful in order to be included in rate base. With regard to AIU's assertion that Hillsboro provides benefits to customers, the Commission concurs with Staff that the method by which it calculates a used and useful percentage inherently takes such benefits into consideration.

While Staff recommends that the Commission rely on the design capacity estimate, 7.6 Bcf, AIU believes the calculation should rely on a 6.4 Bcf capacity because this is the amount of gas that should be cycled at Hillsboro for the next several years. While Staff agrees that it is reasonable for AIU to cycle 6.4 Bcf at Hillsboro for the next several years, Staff maintains that the used and useful calculation should use the design capacity estimate, 7.6 Bcf.

The Commission concurs with AIU that aquifer underground natural gas storage fields are complex structures and that adjustments to the operating characteristics are sometimes appropriate. The Commission, however, believes that IP, AmerenIP, and AIU bear much of the responsibility for the operational problems that have plagued Hillsboro for too long. While it appears that most of those problems may have been resolved or at least mitigated, it is not entirely clear to the Commission that the capacity of Hillsboro has been permanently reduced to 6.4 Bcf. As a result, for purposes of this proceeding, the Commission agrees with Staff that the 7.6 Bcf capacity figure should be utilized in the used and useful calculation. Accordingly, the Commission finds that Staff has correctly calculated that Hillsboro is 96.01% used and useful and that AmerenIP's gas rate base should be adjusted in the manner proposed by Staff.

The Commission rejects AIU's suggestion that because 96.01% is near 100% no adjustment should be implemented in this proceeding. The Commission believes that there is no sound reason for essentially overcharging AmerenIP gas customers. Finally, the Commission notes that in future rate cases, it is willing to revisit the capacity of Hillsboro to review additional data gathered or the result of any studies performed regarding the operation of that storage field.

5. Cash Working Capital

a. AIU Position

AIU explains that a cash working capital (―CWC") requirement is the amount of funds required to finance the day-to-day operations of a utility. A positive CWC requirement indicates that the utility's shareholders are providing funds associated with the payment of expenses prior to the collection of revenues from customers. A negative CWC requirement indicates that the utility's customers are providing funds via the collection of revenues prior to the payment of expenses. AIU indicates that the CWC requirement is calculated by conducting a lead-lag study, which examines the timing of cash flows, both revenues and expenses.

AIU states that the CWC requirement is $6.3 million, $4.1 million, and $10.6 million for AmerenCILCO's, AmerenCIPS', and AmerenIP's gas operations, respectively, and $0.5 million, $2.2 million, and $(1.1) million for AmerenCILCO's, AmerenCIPS', and AmerenIP's electric operations, respectively. AIU asserts that the methods employed to determine the CWC requirement for the gas and electric businesses were consistent with the Commission's decisions in AIU's prior rate case proceedings, Docket Nos. 07-0585 et al (Cons.).

Staff identified four potential issues with AIU's CWC analyses: (1) use of the Gross Lag Methodology versus the Net Lag Methodology, (2) use of consistent expense lead days for Other O&M expenses for both the gas and electric businesses, (3) use of a revenue lag of zero days for pass-through taxes, and (4) the inclusion of service lead time in the expense lead days for pass-through taxes. In its rebuttal testimony, Staff accepted AIU's presentation of bank facility fees and the expense lead time for those fees as presented in testimony and exhibits.

In all other respects, AIU says Staff adopted AIU's CWC analyses. In its rebuttal testimony, AIU states that it accepted Staff's proposed use of the Gross Lag Methodology to calculate the CWC requirements and the use of a consistent expense lead for Other O&M expenses for both the gas and electric businesses. AIU relates that it and Staff agree that the level of CWC allowed should be based upon the final level of cash expenses approved by the Commission in these proceedings. AIU indicates that IIEC submitted direct testimony proposing a collection lag of 21 days. AIU says that in its rebuttal testimony, IIEC also argues that uncollectibles should have been excluded from the calculation of the collection lag.

AIU indicates that it applies a revenue lag to all revenues, with the exception of those associated with pass-through taxes, which consisted of a service lag, a billing lag, a collection lag, a payment processing lag, and a bank float lag. Because Staff has taken the position in prior rate proceedings that pass-through taxes are not associated with the provisioning of a service, AIU excludes the service lag from the revenue lag that was applied to the pass-through taxes. AIU says the service lag excluded from the revenue lag attributed to pass-through taxes was 15.21 days (i.e., 365 days divided by 12 months divided by 2 to reflect the midpoint of the month).

AIU claims that its position reflects the reality that whether or not a service is provided, the Companies still must bill, collect and process the revenues associated with the pass-through taxes. AIU says its customers make only one monthly payment which includes both the amounts associated with monthly services received and the pass-through taxes. AIU contends that no other vehicle exists by which customers make payments.

AIU asserts that unlike arguments presented in prior cases, Staff this time argues that a revenue lag of zero days should be applied to pass-through taxes. Staff contends that there is no lag between a delivery of utility service and the receipt of cash in regard to pass-through taxes. AIU contends that Staff is incorrect and ignores the very purpose of the CWC analyses, which is to examine the timing of cash flows. In AIU's view, Staff ignores the timing of the collection of revenues associated with pass-through taxes. AIU claims Staff proposes a completely contradictory position with regard to the treatment of the expense side of the pass-through taxes.

The infirmity of Staff's position regarding the treatment of pass-through taxes in the CWC analyses, AIU contends, is best shown in Ameren Ex. 31.1. AIU says this exhibit, which uses electric gross receipt taxes as an example, compares AIU's and Staff's positions regarding the timing of receipt of revenues for and the payment of pass-through taxes. AIU asserts that the exhibit demonstrates that AIU remits payment associated with pass-through taxes after 27.53 days while the customers' payment for such taxes is not received for 31.34 days. AIU claims it is remitting payment for pass-through taxes 3.81 days prior to the receipt of payment from customers.

AIU says Staff claims that payment of the pass-through taxes occurs after 42.8 days and that the revenues are in hand for AIU's use immediately. According to AIU, Staff offers no explanation as to how AIU collects the funds associated with the pass-through taxes, if not via the customer's monthly payment. In AIU's view, Staff's position does not reflect the actual timing of cash receipts and cash payments with regard to pass-through taxes.

AIU believes Staff is correct that AIU's revenue lag for pass-through taxes includes factors for billing, collections, payment processing, and bank float and that the expense lead measures the tax period ending date with the date that the funds are removed from AIU's bank account. AIU claims these are precisely the factors which should be measured when conducting CWC analyses. AIU insists that Staff's assertion that AIU's factors do not identify the date that funds are actually received or remitted is incorrect. AIU says the CWC analyses, which Staff adopts in all respects other than the pass-through taxes, are based exclusively on actual receipt and payment dates. AIU urges the Commission to reject Staff's proposed zero-day revenue lag attributed to pass-through taxes in favor of AIU's proposed 31.32-day revenue lag. AIU maintains that its proposed revenue lag reflects the overall revenue lag of 46.53 days less the 15.21-day service lag. In AIU's view, no evidence or analyses have been presented by Staff to demonstrate how the revenues associated with the pass-through taxes are available immediately to the AIUs.

AIU argues that, consistent with its proposed treatment of the service lag, it excludes the service lead from the overall expense lead associated with the pass-through taxes. AIU's position is that if there is no service period, it should not be applied to either the revenue lag or the expense lead. Despite its position that the service lag was correctly excluded by AIU, AIU understands that Staff has proposed that the service lead continue to be included in the overall expense lead. In AIU's view, Staff's position to exclude the service lag but include a service lead is a results-oriented attempt to lower the CWC allowance.

Staff contends that the amounts related to pass-through taxes accrue over a monthly or quarterly period and are remitted, in most cases, after the end of the accrual period and that a service lead is necessary to accurately reflect the lead time. AIU responds that its CWC analyses reflect the actual timing of the payment of the pass-through taxes. AIU insists no service lead is necessary to address anything related to accruals and remittance timing differences.

AIU says the service period is associated with the timing of the provisioning of service. AIU indicates Staff has previously argued that there is no service period associated with pass-through taxes. AIU states that Staff's new position is that there is no service lag associated with the collection of the revenues associated with pass-through taxes, but that there is a service lead associated with the payment of the pass-through taxes. AIU contends that either there is a service period or there is not. AIU believes Staff's position regarding the inclusion of a service lead of 15.21 days to the overall expense lead should be rejected. AIU insists the inclusion of a service period is unsupported and inconsistently applied by Staff. AIU maintains that it accurately and consistently excludes the 15.21 days from both the revenue lag and the expenses lead.

AIU states that Section 280.90 of 83 Ill. Adm. Code 280, "Procedures For Gas, Electric, Water and Sanitary Sewer Utilities Governing Eligibility for Service, Deposits, Payment Practices and Discontinuance of Service" ("Part 280"), of the Commission's rules gives residential customers 21 calendar days from the issuance of the monthly bill to pay the bill before late charges may be assessed. AIU claims its CWC analyses reflect the reality that, while many of their customers pay their utility bills in full and on time, there are customers who are delinquent in the payment of their bills. AIU calculated a collection lag of 28.13 days, based upon an analysis of the aging of accounts receivables during the test year. AIU notes that Staff did not oppose this collection lag.

AIU also argues that the Commission rejected Staff's proposed treatment of the revenue lag for pass-through taxes in a recent Peoples rate case, Docket Nos. 07-0241/0242 (Cons.). AIU says the facts remain the same in this proceeding. According to AIU, there is only one vehicle by which AIU collects payment from its customers and that is via the monthly bill. AIU argues that Staff has provided no additional analyses to support a revenue lag devoid of a billing, collection, payment processing, and bank float lag. AIU believes the Commission decision in AIU's previous rate proceeding remains accurate and should be reaffirmed in these proceedings.

IIEC proposes that the collection lag included in the overall revenue lag should be capped at the number of days allotted for AIU's residential customers to pay their bills from the issuance of the monthly bill. AIU asserts that IIEC provides no support for the reasonableness of its position. AIU also asserts that IIEC has offered no specific suggestions for improvements in collection activities that AIU should implement. AIU claims IIEC has not identified any other companies which had a collection lag limited to the statutory time afforded a customer to pay their bill. AIU contends further that its collection compares favorably to that of other regulated utilities in Illinois. AIU says the approved collection lag for Northern Illinois Gas Company d/b/a Nicor Gas Company ("Nicor") was 33.77 days. AIU adds that Peoples and North Shore filed a collections lag of 32.72 days, while MidAmerican Energy Company has filed a collection lag of 25.68 days.

AIU indicates that in an attempt to support its recommendation, in its rebuttal testimony IIEC alleges that AIU has overstated its collection lag because uncollectible expenses were not excluded from the analyses. While disagreeing with IIEC as to whether uncollectible expenses need to be excluded from the CWC analyses, AIU says it performed a recalculation of the collection lag excluding the uncollectible expenses. AIU asserts that the exclusion of uncollectible expenses from the collection lag had no impact on the overall analysis.

AIU says IIEC disagrees with its method for reducing the percentage contributions of each bill payment period by the same factor, the percentage of revenues represented by uncollectibles. IIEC claims this merely shows that reducing ratios by the same percentage will maintain the relationships of the ratios. However, AIU insists it is realistic to assume that each collection bucket is responsible for the same percentage of uncollectibles because there is no way of knowing in each of the receivable buckets which revenues are uncollectible.

b. Staff Position

Staff indicates that the remaining contested issues between it and AIU involving CWC address the treatment of revenue lag for pass-through taxes collected and the service lead associated with total expense lead days for revenue tax expense. AIU states that the issue at hand is the elapsed time between the receipt of a customer's payment and the remittance of the funds to the appropriate taxing authority. Staff believes this portrayal of the issue oversimplifies the lead-lag study. Staff contends that if AIU was correct, there would be no need to consider billing dates or periods of time for which the pass-through taxes apply. Staff says the analysis would be limited to comparing cash receipt dates and cash disbursement dates only. Staff asserts this is an error in AIU's analysis, which purports to measure the time between receipt of funds for pass-through taxes and remittance of those funds to the taxing authorities.

Staff states that while the utility is liable for the payment of the pass-through taxes it collects from its customers, the utility does not have any investment related to pass-through taxes for which it is awaiting payment associated with that bill. Staff says AIU has an investment in the amount of gas or power that was delivered which it needs to cover by the payment of the bill by the customer. Staff argues that there is no corresponding investment as it applies to pass-through taxes billed. Staff says AIU merely functions as a collection agent for the taxing authorities. In Staff's view, the correct revenue lag for pass-through taxes is zero.

Staff believes the AIU argument regarding the service lead time for expenses is inconsistent with its own definition. Staff relates AIU's position that the service lead time is "associated with the timing of the provisioning of service." (Staff Initial Brief at 27) If there is no service lag on the revenue side, Staff contends that there can not be service lead on the expense side.

Staff argues that the amounts related to pass-through taxes accrue over a monthly or quarterly period and are remitted in most cases in the month after the end of the accrual period. According to Staff, the period of time over which the amounts are accrued is ignored in AIU‘s calculation. Staff believes that to accurately reflect the lead time associated with the payment of pass-through taxes, the service lead time, measured as the mid-point of the accrual period, must be reflected in the weighted lead time calculation.

According to Staff, AIU is misleading in its claim that it is remitting payment for pass-through taxes 3.81 days prior to the receipt of payment from its customers. Staff states that for the gross receipts tax to which AIU refers, the utility‘s liability is based upon the gross receipts which were received from customers during the preceding calendar month. Staff says the 31.34 days revenue lag is simply a calculation for the average time for all revenues to be in the control of the utility. Staff claims that this does not mean that no revenues are available to pay pass-through taxes until after day 31. To compare that number with the expense lead for pass-through taxes which are all paid on a date certain for each type of tax is, in Staff's view, misleading.

Staff believes AIU's assertion that under Staff‘s proposal, revenues are in hand immediately is also misleading. Staff says pass-through taxes do not represent a cost of service that the utility has provided and for which it must await recovery through revenues. Staff‘s position is based on the fact that pass-through taxes are not an investment on which the utility needs to earn a return through the rates it charges. AIU agrees that it simply acts as a conduit for the funds to flow through.

Staff contends that the service period, as it relates to the expense lead calculation, is based upon the period of time over which the liability is incurred. Staff asserts that for pass-through taxes, which accrue over a month or quarterly period, it is consistent with AIU‘s definition of expense lead to include the service period in the calculation for pass-through taxes. Staff argues that in contrast, the service period for revenues is associated with the timing of the provisioning of service. Staff says that since no service is provided by the utility related to pass-through taxes, there can be no service lag associated with the revenues.

c. IIEC Position

IIEC believes AIU's use of a 28.13-day collection lag is overstated and unreasonable for three reasons. First, a 28.13-day collection lag suggests to IIEC that on average every customer of AIU, with exception of the Non-Residential Special

Customer Type, pay its bills beyond the due date and late payment grace period. Second, the data used by AIU to develop its collection lag contains uncollectibles, and uncollectibles expenses are included as a component of AIU‘s cost of service. Third, the collection lag period is inconsistent with Commission rules. For these reasons, IIEC recommends a collection lag of 21 days.

With regard to its first criticism of AIU's 28.13-day collection lag, IIEC questions the assumption that nearly every customer pays its bills late. IIEC argues that the 21-day collection lag it recommends matches the authorized collection period for the residential class and is longer than the collection periods for commercial and industrial customers. IIEC adds that many customers pay their bills sooner than the last allowable day. IIEC submits that use of a 21-day collection lag is conservative. In response to AIU's claim that it should have provided recommendations on how a 21-day collection lag could be achieved, IIEC asserts that AIU‘s ―real world” argument does not provide substantive evidence for increasing the collection lag above and beyond the payment period defined by Commission rule. IIEC contends that it has no responsibility to prove the reasonableness of the Commission‘s collection rules. Rather, IIEC asserts that AIU must prove the reasonableness of its proposed collection period.

Concerning uncollectibles, IIEC contends that these dollars represent amounts that are included separately as a component of AIU‘s cost of service, and recovered through charges to customers who do pay their bills. IIEC argues that including the uncollectibles is an error in AIU's collection lag calculation and removing them would decrease the collection lag calculated by AIU. Inclusion of the uncollectibles in the accounts receivables, AIU explains, improperly increases the receivable balance used to develop the weighted lag periods. Those dollars, IIEC continues, will never be reduced by customer payments. IIEC states that reducing both the billed revenues used to weight AIU's average lag calculation and the accounts receivable balances for uncollectibles, which have no lag period end date, will decrease the calculated collection lag from the level proposed by AIU.

IIEC states that in the collection lag study, AIU used bill payment time periods to weight the CWC requirements beginning with current bills and going through payment periods of 0 to 30, 30 to 60, and 60 to 90 days. IIEC says these are accounts receivable that are paid before the due date, and bills paid after 0 to 30, 30 to 60 or 60 to 90 days. AIU multiplies the uncollectible percentage for each period by the test year revenue in each of the 0 to 30, 30 to 60, and 60 to 90-day bill payment periods. In doing so, IIEC says AIU assumed that each bill payment period contributed an identical percentage of its included revenues to the amount that ultimately becomes uncollectible. According to IIEC, AIU opines that this is a realistic assumption, even though AIU admits it used the same percentage simply because it does not know, for each of the bill payment periods, the actual percentage of revenues that become uncollectible. IIEC claims this unsupported default assumption shoehorns bill payment periods of different size and age into the same circle.

IIEC says AIU agrees that the size of the billing period revenue amount matters in the weighting that goes to that period. According to IIEC, AIU states the largest collection period is either the current period or the 0 to 30-day period. IIEC contends that this weighting error is added to the weighting error that resulted from failing to remove uncollectibles from the analysis. IIEC believes that AIU's failure to account for the size of the billing periods, the amount of uncollectibles in each period, and the removal of the same uncollectible percentage from each period does not give a realistic picture of the true impact of uncollectibles on the CWC analysis.

IIEC claims that AIU ignores the incentive customers have to pay their bills on time because of the ability to charge them a late payment fee. IIEC says AIU also ignores the fact that the 21-day collection lag period recommended by IIEC is more than a third longer (7 days) than the period specified in the Commission‘s rules for the payment of non-residential customers bills (14 days). IIEC also notes that the 28.13-day collection lag is twice the amount of time that commercial and industrial customers have to pay their bills (14 days). The collection lag period recommended by IIEC is greater than the average residential and non-residential collection period specified in the Commission‘s rules. IIEC states that if one considers AIU's total revenue and the percentage of that revenue that comes from the customer classes with a 14-day payment period, i.e., non-residential customers, one would find that they pay approximately 48% of total revenues for AmerenIP; 57.4% for AmerenCIPS; and 56.1% for AmerenCILCO. IIEC believes that in this factual context, AIU‘s assertions that it must wait, on average, more than twice the payment period applicable to half its revenues are not credible. IIEC recommends a collection lag of 21 days and argues that any greater period would need to be further investigated and should not be accepted without more evidence than AIU has provided.

In IIEC's view, comparisons to other utilities in this instance will not help the Commission in its determination. IIEC says AIU does not offer any evidence to establish whether the pertinent factual circumstances are even comparable. IIEC suggests that if those lags were calculated using the same flawed methodology used by AIU (uncollectibles included, payment period weightings distorted), those studies are also flawed and their results unrealistic. IIEC states that collection lags of 33.77 (Nicor) and 32.72 (Peoples) days suggest that on average, every customer of those utilities has two unpaid utility bills in hand every month. IIEC claims that to suggest that on average, every customer would continuously have two bills payable to the utility should raise serious questions about the validity of the analysis. IIEC believes AIU's attempt to support its collection lag with other flawed collection lags has no merit.

d. Commission Conclusion

IIEC identified what it considers to be two problems with AIU's computation of CWC: the inclusion of uncollectibles and the weightings applied to outstanding bills. To rectify these problems, IIEC recommends that AIU's CWC be based on 21 lag days rather than the AIU's lead lag studies. The basis for IIEC's 21 lag days is the Commission's rules, specifically Part 280. AIU acknowledges that uncollectibles, theoretically, should be excluded from a lead lag study but asserts that, in this instance, the inclusion of uncollectibles has negligible impact on the results of the study. With regard to the weightings, AIU asserts that it is necessary to make an assumption and the assumption it has made is reasonable.

The Commission has concerns about AIU's proposed method for calculating the CWC requirement. The Commission understands that IIEC's reason for proposing 21 lag days in that it is the maximum lawful period customers can delay payment. Section 285.2070 of Part 285 specifically contemplates the use of a lead/lag study. AIU presented a detailed lead/lag study using methods that have been adopted by the Commission in numerous previous proceedings, but AIU assumed, rather than proved, the collection lag periods used in its study. The absence of empirical evidence supporting the collection lag assumptions used in Ameren's lead/lag study weighs against the utility, which has the burden of proof in this proceeding. Under these circumstances, IIEC's proposal to use a 21 day collection lag in calculating the CWC requirement is hereby adopted.

The remaining contested issues between Staff and AIU involve the treatment of revenue lag for pass-through taxes collected and the service lead associated with total expense lead days for revenue tax expense. For revenue lag, Staff believes that pass-through taxes are different than other utility cash inflows for two reasons: there is no utility service associated with pass-through taxes and the utility does not have an "investment" associated with pass-through taxes. With regard to expense lead, Staff asserts that the amounts related to pass-through taxes accrue over a monthly or quarterly period and are remitted in most cases in the month after the end of the accrual period. It is Staff's position that the period of time over which the amounts are accrued is ignored in AIU's calculation. Staff contends that to accurately reflect the lead time associated with the payment of pass-through taxes, the service lead time, measured as the mid-point of the accrual period, must be reflected in the weighted lead time calculation. With regard to expense lead, Staff also states that AIU has omitted a service lead time for pass-through taxes, using only payment lead time and bank float lead time in determining the weighted lead time.

As an initial matter, the Commission accepts Staff's argument that the utility has no "investment" associated with pass-through taxes. Since every dollar for pass-through taxes is collected from the ratepayers, the inflows and outflows earmarked for these taxes should be perfectly balanced. Thus the need for CWC should not arise with respect to pass-through tax transactions. This conclusion is consistent with prior Commission decisions. Nicor Docket No. 08-0363 at 11-12.

Staff distinguishes pass-through taxes from other cash flows in that unlike other revenue, pass-through taxes are not directly associated with the provision of utility service. The Commission believes that Staff makes a legitimate point here. The Company would have us believe there is an additional and measurable cost to pass-through taxes but fails to illustrate how a tax that is completely ratepayer-funded could generate any costs or expense. This is simply not the case. The Commission finds that Staff's proposed adjustment to the CWC requirement must be accepted.

6. Gas in Storage

a. AIU Position

Staff asserts that AIU's reliance on 2008 gas costs to value its requested working capital allowance for gas in storage amount results in an overstatement of the costs due to the reduction in natural gas prices since 2008. Staff recommended in direct testimony that AIU provide in its rebuttal testimony an updated calculation for its working capital allowance for gas in storage that follows the same pricing methodology that AIU proposed and was accepted by the Commission in AIU's last rate case.

AIU believes that while it is appropriate to reflect updated information on gas in storage pricing, AIU opposes Staff's proposal to use 2009 gas pricing to determine the value of gas in storage. According to AIU, Staff's proposal does not take into account the changed circumstances that AIU is experiencing with respect to gas prices since the prior case. AIU indicates the price of gas has declined since 2008 and has exhibited significant variability since its last rate case. In order to reflect this past variation and account for the fact that further gas price variations can be anticipated into 2010, AIU argues that a more appropriate method of valuing gas in storage would be to use a three-year average of gas prices through December 2009. AIU claims the three-year average calculation smoothes out the large fluctuation of natural gas prices which can occur over a short period of time. AIU contends that natural gas is among the most volatile commodities that are traded, so using a three-year average will reduce the impact that volatility has on storage working capital. AIU adds that this methodology addresses Staff's concern about using more recent gas prices by reflecting gas prices through December 2009.

To calculate the value of gas in storage, AIU uses actual prices for December 2006 to August 2009. AIU says price estimates used to record to the general ledger were used for September 2009. AIU indicates that hedged gas and Inside FERC ("IFERC") prices were used for October 2009. AIU also states that hedged gas prices and New York Mercantile Exchange ("NYMEX") prices were used for November and December 2009. AIU asserts that these prices represent the most accurate for valuing gas in storage in this time period, since it is the end of the injection season. AIU says the volumes were also calculated as a three-year average, and adjusted for contract and other known changes.

AIU indicates that in its last rate case, Staff requested that volumes of gas in storage be updated for known contract changes. In response, AIU stated that the price of gas should be updated to match the updated volumes. AIU says it updated the value of the working capital allowance for gas in storage based on updated volumes and to reflect AIU's price hedging, or, where prices were not hedged, to reflect forward NYMEX strip prices for the period when rates would come into effect. According to AIU, the

Order in Docket Nos. 07-0585 et al (Cons.) found that the use of the NYMEX data for the period April through October 2008 (where 2006 was the test year), which is the traditional injection season, was appropriate. The Commission concluded that, —in this instance, the price proposal of AIU is reasonable when used in conjunction with Staff's proposed quantities of gas." (Docket Nos. 07-0585 et al (Cons.), Order at 78) AIU says that in this case, Staff proposes use of 2009 prices, which do not reflect the forward prices for the period when the rates would come in effect (expected to be May 2010). AIU argues that Staff's approach is not consistent with the prior Order.

AIU claims that Staff's argument that 2008 gas prices are an —outlier," confirms that gas prices are volatile and so are appropriately subject to averaging to smooth out the variations. AIU says that in the prior case, it proposed a methodology to reflect projected gas prices during the summer injection season of 2008 because the working capital allowance for storage was calculated at the beginning of the injection season (April 2008). According to AIU, that concern is not present in this case, as the working capital allowance for storage is being calculated at the end of the injection season when actual prices are known (October 2009). AIU also argues that using a three-year average is consistent with many other price calculations for commodities with variable prices AIU is proposing in this rate case, such as transportation fuels.

AIU contends that the prices used in the three-year average it is proposing include the most current prices through December 2009, which is consistent with the use in Docket Nos. 07-0585 et al (Cons.) of current pricing to match projected changes in volumes. AIU believes the three-year average calculation also sets a method or a template that can be used in future rate cases without regard to the timing of the calculation. In addition, AIU claims that it calculates the volume of gas in storage as a three-year average (reflecting known changes), so the use of a three-year pricing average matches the prices to volumes. AIU acknowledges that in utilizing a three-year average of gas prices to value gas in storage, AIU proposes a different method for valuing gas in storage in this case than the prior case. AIU asserts that circumstances have changed since the last case, and the three-year average proposal is appropriate.

AIU insists that Staff is incorrect that 2008 gas prices are so different from historical and projected prices that 2008 prices must be excluded from the valuation of gas in storage. Although Staff states that a review of the 2007, 2009, and current NYMEX future prices for 2010 and 2011 demonstrates that 2008 gas prices were outliers, AIU complains that this analysis is based on one day's NYMEX close, November 2, 2009. AIU argues that reviewing the entire trading period for a specific month provides a significantly different picture. AIU claims the simple average of the daily NYMEX closing price at which January 2011 has traded is \$8.418 (January 3, 2008 through November 25, 2009). AIU states that this price represents the approximate value that AIU would have had the opportunity to purchase gas on a forward contract basis to be delivered in January 2011. AIU says if one compares this price to Staff's one day settlement price on 11/2/09 for January 2011 of \$6.795 and to the 2008 price AIU used of \$8.335 to \$8.903, then the 2008 prices AIU uses in its analysis can not be considered outliers. AIU asserts that reviewing the entire NYMEX trading period for any one month supports the three-year average pricing to smooth out the volatility of natural gas prices.

AIU also claims that 2009 gas prices are not more representative of expected prices than AIU's proposal. AIU says that the NYMEX futures contracts provide an indication of the gas market's expectations for future prices. According to AIU, the NYMEX futures contracts also show that natural gas prices are extremely volatile. AIU says the January 2011 NYMEX contract has traded in more than a $5.00 range since it began trading until November 25, 2009 (from a low of $6.426 to a high of $11.822). AIU describes this as an extreme range and asserts that no one can know what future gas prices will be, which AIU believes supports using a three-year average approach to calculate the value of gas in storage used for working capital purposes.

b. Staff Position

Staff notes that it and AIU agree to reduce the working capital allowance for gas in storage (value of gas in storage) component of the total materials and supplies balances by an accounts payable percentage of 6.63%. Staff believes its proposed valuation of gas in storage should be used in the calculation of the accounts payable adjustment. If the Commission should reject Staff's valuation of gas in storage, and accept the AIU valuation, the AIU amount for gas in storage presented in Ameren Ex. 51.10 should be used in the calculation of the accounts payable adjustment.

Staff indicates that the only remaining issue involving AIU's requested working capital allowance for gas in storage for its gas utilities involves the gas price to apply to the gas volumes. Staff recommends the use of the 2009 gas price information, whereas AIU recommends the use of a three-year average to price this gas. As a result of this pricing difference, Staff recommends a reduction of $1,795,143 to AmerenCILCO's requested amount (Staff Ex. 25.0, Schedule 25.01 CILCO-G, l. 3), a reduction of $3,662,720 to AmerenCIPS' requested amount (Id., Schedule 25.02 CIPS-G, l. 3), and a reduction of $12,255,211 to AmerenIP's requested amount (Id., Schedule 25.03 IP-G, l. 3).

According to Staff, AIU's proposal to average the 2007-2009 gas prices to value its gas utilities' requested working capital allowance for gas in storage amounts allows AIU to place partial reliance on the gas prices it experienced in 2008 within its calculation. Staff claims the 2008 gas prices were the highest prolonged prices for natural gas that the industry has experienced during the last 20+ years. Staff contends that a review of the gas prices that AIU provided, as well as the NYMEX future prices, demonstrates that the 2008 gas prices were outliers. Staff argues that AIU's reliance on those values causes a significant increase in the average price that AIU advocates.

Staff states that a review of the NYMEX gas future prices, based on November 2, 2009 values, for the coming years shows that the market place does not currently expect the forward gas prices to return to the gas price levels experienced in 2008. Staff says the average price of NYMEX futures for 2010 and 2011 are $5.51/dekatherm

("Dth") and $6.50/Dth, respectively. Staff believes this supports its position that the 2008 gas prices are price outliers. Staff also argues that since ratepayers already experienced those high gas costs through their 2008 gas bills, it is not fair to require the customers to continue paying these higher gas costs when there is no indication that gas costs will return to those levels in the near future.

Staff admits that the 2009 gas costs include several months of data with gas prices that are significantly lower than those experienced by AIU in 2008. Staff indicates, however, that the 2009 gas cost calculation is based on the 13-month average of the month ending values from December 31, 2008 through December 31, 2009. According to Staff, this means that a portion of the 2009 gas costs includes gas volumes and values from natural gas that AIU injected into storage during 2008. Staff asserts that the 2009 gas cost calculation would have several months of data, namely, December 2008, January through March or April 2009 (depending on the specific characteristics of the leased storage service or on-system storage field) whose gas prices are primarily based on the higher than normal prices from 2008. Staff argues that while 2009 gas prices dropped significantly, these much lower gas prices were offset within AIU's weighted average cost of gas calculation by the much higher 2008 gas prices that remained in the 2009 calculation. In Staff's view, the gas prices that make up the 2009 average are a combination of both high and low gas prices and, as a result, the 2009 prices provide a reasonable proxy for the gas costs that AIU may experience once rates go into effect.

Staff states that while no one knows with certainty what the future price of gas will equal, the NYMEX futures contracts provide an indication of the gas market's expectations for future prices. Staff says those future prices show that the average NYMEX future prices for 2010 are lower than the 2009 gas costs recommended by Staff and that the average 2011 NYMEX future prices track very closely with the 2009 gas cost. Staff also says that the AIU gas utilities have locked in some of the lower gas prices that existed in 2009 through its hedging activity for 2010 and beyond. Staff asserts that for the storage injection months, roughly April through October, AIU has locked in a portion of its gas purchases, which will include some portion of the gas injected into storage. Staff contends that these values show that AIU's existing hedged positions for 2010 and 2011 are more in line with Staff's proposal to use the 2009 gas costs than AIU's proposal for a three-year average that includes the high gas prices from 2008. Staff insists that going forward its proposed 2009 gas prices are more representative of expected prices than AIU's proposal.

AIU asserts that Staff's proposal to use 2009 prices is inconsistent with the Commission's prior AIU rate case Order because the prior order approved the use of NYMEX forward pricing to determine prices in 2008, which was two years after the 2006 test year, whereas Staff's proposal in this case uses 2009 gas prices which are only one year after the 2008 test year. Staff does not dispute the timing AIU notes, but disputes AIU's argument that this timing makes Staff's proposal inconsistent with the Commission's prior Order. Staff states that in the instant case and in its most recent rate case proceeding before the Commission, AIU selected a historical test year. Staff claims that Commission rules limit changes to the test year data for historical test years to known and measureable changes. Staff says the Commission entered its Order in Docket Nos. 07-0585 et al (Cons.) on September 24, 2008, which means the evidentiary phase of the proceeding occurred during 2008. In the instant proceeding, Staff says the evidentiary phase took place in 2009. Staff claims it is making use of the most recent known and measurable data in the instant proceeding, which is consistent with the Commission's practice in Docket Nos. 07-0585 et al (Cons.).

AIU also notes that a review of NYMEX closing prices for the January 2011 contract for the period January 3, 2008 through November 25, 2009 shows a large variance and AIU claims that the average of that month's price shows AIU's 2008 gas prices are not outliers. Staff says that AIU is comparing a single month's price, January, to the average price over the year, which Staff claims is not a valid comparison. Staff also asserts that a recent (November 2, 2009) review of NYMEX future prices for 2010 and 2011 shows that the gas prices Staff used in its calculation, are higher than the NYMEX average price for 2010 and track very closely to the 2011 prices. Staff contends that the market's current expectation of gas prices demonstrates that AIU's 2008 gas prices were outliers and Staff's proposal more closely corresponds to the expected future prices.

c. AG/CUB Position

According to AG/CUB, AIU has failed to support the use of a different pricing methodology from what it requested and the Commission approved in AIU's last rate case. AG/CUB says AIU uses a three-year average that places partial reliance on 2008 gas prices. AG/CUB notes that Staff claims the 2008 gas prices were the highest prolonged prices for natural gas that the industry has experienced during the last 20+ years. In AG/CUB's view, AIU's goal here is clear: to develop a ―template that can be used in future rate cases," at a point in time that would include the record high natural gas prices of 2008. AG/CUB contends this is especially inappropriate given the recent downward pressure on natural gas prices. AG/CUB recommends the Commission adopt Staff's propose pricing methodology.

d. Commission Conclusion

To calculate the value of gas in storage, AIU uses actual prices for December 2006 to August 2009. AIU says price estimates used to record to the general ledger were used for September 2009. AIU indicates that hedged gas and IFERC prices were used for October 2009. AIU used hedged gas prices and NYMEX prices for November and December 2009. In contrast, Staff proposes that gas in storage values be determined using gas costs from calendar year 2009. AG/CUB supports Staff's recommendation.

As an initial matter, the Commission can not help but observe that on four issues – gas in storage, transportation fuel, maintenance of mains, and injuries and damages – both AIU and Staff have proposed using four different measurement periods. While the

Commission recognizes that different measurement periods might be appropriate for different circumstances, it seems that even the slightest effort and coordination of a parties' overall case would not have produced the situation present in this proceeding. As a result, the Commission suggests that in future proceedings, both AIU and Staff provide additional clarity for proposing different measurement periods so the Commission has a better understanding of why different measurement periods may be appropriate.

In the Commission's view, the record shows that natural gas prices are volatile. The gas prices that Staff characterizes as outliers are evidence of this fact. The Commission also notes that Staff‘s proposal relied on the most recent known and measurable information. Staff demonstrated that the current expectations of the marketplace for future gas prices are consistent with its proposal. Further, Staff demonstrated that AIU has locked in a portion of its gas costs for 2010 and beyond at levels that are more consistent with its recommendation, than AIU‘s proposal. Finally, the Commission notes that Staff‘s proposal is consistent with the Commission‘s ruling on this same issue in AIU‘s 2007 rate case proceeding. As such, the Commission accepts Staff‘s proposal to value AIU‘s working capital allowance for its gas in storage.

7. OPEB Net of ADIT

a. AIU Position

AIU notes that Staff and AG/CUB propose an adjustment to reduce rate base by the accrued liability for other post employment benefits (–OPEB"), which represent the employer‘s obligation for such benefits as health care, life insurance, tuition assistance, and other post retirement benefits outside of a pension plan. AIU indicates that the revenue requirement impact of this proposed adjustment is approximately $7 to $8 million, depending on which party‘s recommended cost of capital is assumed. AIU believes this adjustment is appropriate, in part, for AmerenIP. AIU insists that it is not appropriate for AmerenCIPS or AmerenCILCO and should be rejected.

AIU says no party disputes that AIU‘s prudent cost of service includes the cost of OPEBs paid for former employees and retirees. AIU indicates that OPEB is the employer‘s obligation for post retirement benefits, which accrues to the employee‘s benefit over the employee‘s term of service. AIU states that the accounting treatment for OPEBs is prescribed by Financial Accounting Standard ("FAS") 106. According to AIU, whenever the cumulative amount of FAS 106 expense is greater than contributions the employer has made to the trust fund used to pay OPEBs, an OPEB liability exists.

In its direct case, AG/CUB witness Effron proposed an adjustment to reduce AIU‘s rate base by the level of accrued OPEB liabilities. According to Mr. Effron, the accrued OPEB liabilities represent the excess of OPEB expense recorded by AIU over amounts actually paid, in other words, ratepayer-supplied OPEB funds. AIU says AG/CUB's claim that the entire accrued OPEB liability represents ratepayer-supplied funds is based on an unsupported assumption that ratepayers have supplied all of the funds giving rise to the OPEB liabilities. AIU argues that only AmerenIP historically has funded OPEBs based in part on amounts received from ratepayers. AIU believes an adjustment to reduce rate base by the accrued OPEB liability for AmerenIP is therefore appropriate, but only to the extent that AmerenIP's accrued OPEB liability represents ratepayer-supplied funds. AIU asserts that Ameren Ex. 29.17 provides the appropriate adjustment to reduce rate base by the ratepayer-supplied portion of AmerenIP's OPEB liabilities.

With respect to AmerenCIPS and AmerenCILCO, however, AIU asserts that they historically have not directly tracked ratepayer-supplied OPEB funds. Because ratepayer-supplied funds were not tracked, AIU insists it is erroneous to conclude that these liabilities were funded entirely by ratepayers AIU argues that contrary to funding OPEBs based on ratepayer supplied funds, funding considerations would have considered the availability of cash or borrowed funds to cover accounting accruals in accordance with FAS 106 or related accounting guidance.

AIU indicates that Staff adopted the AG/CUB adjustment in rebuttal and argues a similar rationale. According to Staff witness Ebrey, ―Ratepayers have supplied funds for future obligations; therefore, a source of cost free capital has been provided to the utility which should be recognized in the revenue requirement as a reduction from rate base." (AIU Initial Brief at 53, citing Staff Ex. 15.0 at 25) AIU responds that Staff's and AG/CUB's assumption that the OPEB liability represents ―ratepayer supplied funds" or a source of ―cost free capital" rests on the false premise that all funds received and spent by AIU originates from ratepayers. AIU contends this is not correct. AIU states that in the first instance, utilities are capitalized by investors. AIU contends that utilities use investor-supplied capital to invest in plant and provide service. AIU asserts that part of ratemaking theory is to compensate investors by providing a return on, and return of, capital used to provide service. AIU claims that ratepayers in effect return the investment through the rates they pay. AIU argues that if rates do not include an allowance for a certain expense, investors are not compensated for that expense.

AIU contends that ratepayers provide a source of ―cost free capital" for an expense item only to the extent that they have actually supplied funds for that expense item through the rates they pay. In determining whether OPEB liabilities constitute ratepayer-supplied funds, AIU says the question then becomes how many dollars have ratepayers contributed for OPEBs. AIU disagrees with Staff that it is possible to know the answer to this question. AIU claims the level of OPEB expense included in rates is based on FAS 106, irrespective of what the utility paid in OPEBs. According to AIU, although actual revenues and expenses may change after a rate case test year, the level of OPEB expense included in rates does not. If one assumes that cumulative FAS 106 expense has been fully reflected in rates since that adoption of FAS 106, then AIU insists the liability properly represents ratepayer-supplied funds, as AIU agrees is the case in part with AmerenIP. AIU contends the only way to prove this assumption is to analyze the level of FAS 106 expense recovered from ratepayers over the period giving rise to the liability, which Staff did not do. AIU asserts that absent such an analysis, the statement that the OPEB liability constitutes ―ratepayer supplied funds" or a ―cost free source of capital" is unsupported. AIU asserts that the AG/CUB's testimony reflects no such analysis either.

With regard to Staff's quotation from the Order in Docket Nos. 06-0070 et al (Cons.) that ―Ratepayers are not paying this cost of service as a separate line item, and it is inappropriate to treat it as such," AIU argues that this language does not mandate the deduction of the entirety of a utility's OPEB liability from rate base in all instances. (Order at 27) Although there is not a line item on customers' bills for OPEBs, AIU states that OPEBs are an element of the utility's cost of service. AIU asserts that this expense and others are aggregated to develop an overall revenue requirement. If the revenue requirement (and associated rates) does not include an allowance for OPEBs, AIU contends that it is inaccurate to say that liabilities associated with OPEBs constitute ratepayer-supplied funds. AIU argues that ratepayers supply funds for an expense only to the extent the expense is included in rates. In AIU's view, the issue is not whether ratepayers pay a portion of OPEBs as a separate line item; the threshold question is whether ratepayers have paid a portion of this cost of service at all. If they have not, AIU claims mathematics precludes the possibility that the OPEB liabilities were entirely or even partially ratepayer-funded.

AIU insists that there is no factual support for the assumption that OPEB liabilities arise entirely from ratepayer-supplied funds. Because it believes that it has no burden to disprove Staff and AG/CUB's unsupported assertions, AIU claims that it is Staff and AG/CUB's burden to prove the basis for their adjustment. In AIU's view, because Staff and AG/CUB have not adequately supported their proposed adjustment, the Commission must reject it.

b. AG/CUB Position

AG/CUB states that to the extent that the cumulative accruals for OPEB are greater than the actual cash disbursements, AIU has accrued liabilities for OPEB. AG/CUB asserts that these accrued liabilities represent ratepayer-supplied OPEB funds. AG/CUB contends that because ratepayers have supplied funds for future obligations, a source of cost-free capital has been provided to the utility, which AG/CUB believes should be recognized in the revenue requirement as a reduction from rate base.

In this instance, AG/CUB avers that the accrued OPEB liabilities as of December 31, 2008 should be deducted from plant in service in the calculation of AIU's rate bases in these cases, as proposed by Mr. Effron and supported by Staff. AG/CUB states that recognition of the ratepayer-supplied OPEB funds reduces the AmerenCILCO electric rate base by $20,077,000, the AmerenCIPS electric rate base by $3,774,000, the AmerenIP electric rate base by $14,971,000, the AmerenCILCO gas rate base by $15,535,000, the AmerenCIPS gas rate base by $1,686,000, and the AmerenIP gas rate base by $8,891,000. AG/CUB notes, however, that with the exception of AmerenIP, AIU has not recognized these balances in the calculation of rate base.

AG/CUB states that for the most part, AIU accepts AG/CUB's adjustment to reduce the AmerenIP rate base for accrued OPEB net of deferred income taxes. AIU says AIU disagrees with making the same adjustment to the AmerenCILCO and AmerenCIPS rate bases because it argues those two companies did not track ratepayer-supplied funds. According to AG/CUB, while that may be the case, AIU has not presented any sound reason to treat the AmerenCILCO and AmerenCIPS accrued OPEB differently from the AmerenIP accrued OPEB. Whether AmerenCILCO and AmerenCIPS did or did not track ratepayer-supplied funds, AG/CUB argues, has nothing to do with whether the accrued OPEB balances are ratepayer-supplied funds. AG/CUB claims there is no dispute that both AmerenCILCO and AmerenCIPS have recorded the OPEB accruals on their books of account and that the accrued balances represent the amounts that have been accrued as expense in excess of actual cash dispersed. AG/CUB states that the failure of AmerenCILCO and AmerenCIPS to directly track the extent to which expenses have been recovered in rates does not mean that the accrued balances do not represent ratepayer-supplied funds.

AG/CUB states that in a Nicor case, the Commission determined, so long as the companies continue to control the ratepayer-supplied OPEB funds, the OPEB deduction should be recognized in the determination of rate base. (AG/CUB Initial Brief at 20, citing Docket Nos. 95-0219, Order at 10) AG/CUB asserts that in a prior AIU rate case, the Commission found that AmerenCILCO, AmerenCIPS, and AmerenIP electric delivery services rate bases should be reduced by the accrued OPEB liabilities. (Id., citing Dockets Nos. 06-0070 et al (Cons.), Order at 27) Finally, AG/CUB avers that in the last AIU rate case, Docket Nos. 07-0585 et al. (Cons.), AIU agreed that the accrued OPEB should be deducted from rate base, and the Commission adopted this adjustment, finding it reasonable and appropriate. (Id. at 21, citing Docket No. 07-0585 et al (Cons.), Order at 7) AG/CUB claims that AIU has offered no change in circumstances, or any other reason to explain why the Commission should deviate from its prior treatment of OPEB in this proceeding.

c. Staff Position

Staff recommends that the Commission approve the adjustments to reflect the impact of the OPEB liabilities in the calculation of AIU‘s rate bases as proposed by Staff and AG/CUB. Staff says the OPEB liabilities represent ratepayer-supplied funds and should be reflected as a reduction to rate base. Staff avers that this is consistent with the last two AIU rate case proceedings, where the Commission approved the reduction to rate base for accrued OPEB liabilities. Staff reflected those adjustments in the rebuttal revenue requirements for each utility. Staff acknowledges that AIU accepts the OPEB adjustment for AmerenIP.

Staff asserts that during cross-examination, AIU tried and failed to illustrate that funds collected from ratepayers could be tracked to specific cost of service line items. Staff witness Ebrey explained that ratepayers are paying a rate based on an overall cost of service and that the rates are not tied specifically to any certain line item in the revenue requirement. Staff believes such an analysis would not be possible.

Staff avers that AIU also attempted to draw a comparison to Ms. Ebrey's proposal in the AIU uncollectibles rider proceeding, Docket No. 09-0399. Staff believes there are a number of significant differences that make such a comparison invalid. Staff asserts there is a direct connection between the amounts of uncollectible expense included in the revenue requirement to the pro forma revenues approved in the rate case. Staff claims this is not the case with OPEB costs because OPEB costs do not vary with the level of revenues. Staff also states that new provisions under Public Act 96-0033, effective July 10, 2009, provide for the recovery of uncollectible expense through both base rates and through the rider mechanism. Staff says that Sections 16-111.8(c) and 19-145(c) of the Act mandate that the Commission ―verify that the utility collects no more and no less than its actual uncollectible amount" in each applicable reporting period. In order for the Commission to comply with the statute, Staff asserts it was necessary to establish a method to track the recovery of uncollectible expense. Staff claims this is not the case with OPEB costs because OPEB costs are only recovered in base rates.

Staff believes its position is supported by the Commission's Order in a prior AIU rate proceeding (Docket Nos. 06-0070 et al (Cons.)) that came to the same conclusion that AG/CUB and Staff propose in this case. In Staff's view, the evidence demonstrates that the OPEB liabilities represent ratepayer-supplied funds. Consistent with its findings in prior AIU rate cases, Staff recommends that the Commission accept the same adjustment in the current cases.

d. Commission Conclusion

While AIU, AG/CUB, and Staff agree that OPEB liability should be subtracted from AmerenIP's rate base, there is disagreement as to the amount of that reduction. Mr. Effron's rebuttal testimony indicates that for AmerenIP the balance on Schedule DJE-R-4 represents the elimination of AIU witness Stafford's offset to the AmerenIP accrued OPEB for the portion of accrual that was not tracked. For purposes of this proceeding, the Commission finds the AG/CUB proposed adjustment to rate base for AmerenIP to be reasonable and it is hereby approved.

With regard to AmerenCILCO and AmerenCIPS, however, AIU argues that because ratepayer-supplied funds were not tracked, it is erroneous to conclude that these liabilities were funded entirely by ratepayers. Apparently, AIU does not see that one could also make the opposite argument--that because ratepayer-supplied funds were not tracked, it is erroneous to conclude that these liabilities were funded entirely by shareholders. In previous rate cases, including recent rate cases for AIU, the Commission has subtracted accrued OPEB liabilities from rate base. AIU has the burden to demonstrate that its rate bases are reasonable and with regard to this issue, the Commission finds that AIU has offered nothing but a single unsupported assertion. With respect to AmerenCILCO and AmerenCIPS, the Commission finds AIU's position must be rejected. The Commission concludes that AG/CUB's proposal to reduce

AmerenCILCO's and AmerenCIPS' rate bases by the amount of accrued OPEB liability is reasonable and it is hereby approved.

V. OPERATING REVENUES AND EXPENSES

A. Resolved Operating Expense Issues

1. Annualized Labor

Staff recommends an adjustment to AIU's proposed annualized labor expense. Specifically, Staff recommends disallowance of wage increases for management employees projected for April 1, 2010 and wage increases for union employees based on contract increases effective July 1, 2010. To reduce the number of contested issues, AIU accepts Staff's recommended adjustment to its proposed annualized labor expense. The Commission finds Staff's proposed adjustment to annualize labor expense to be reasonable for purposes of setting rates in this proceeding and it is hereby approved.

2. Federal Insurance Contributions Act Corrections

Staff recommends certain corrections to AIU's proposed adjustments to the Federal Insurance Contributions Act ("FICA") tax expense. In addition, related to its recommended adjustment to AIU's proposed annualized labor expense, Staff recommends a further adjustment to AIU's FICA tax expense. To reduce the number of contested issues, AIU accepts Staff's recommended adjustment to the proposed adjustment to the FICA tax expense. The Commission finds Staff's proposed adjustment to AIU's FICA tax expense to be reasonable and it is hereby approved.

3. Outside Professional Services

Staff recommends an adjustment to AIU's Outside Professional Services expense to remove fees paid to Jacobs Consultancy, Inc. to perform an electric utility workforce analysis study for AIU, the results of which were to be presented to the General Assembly by the Commission. To reduce the number of contested issues, AIU accepts Staff's recommended adjustment to AIU's Outside Professional Services expense. The Commission finds Staff's proposed adjustment to AIU's Outside Professional Services expense to be reasonable for purposes of this proceeding and it is hereby approved.

4. Bank Facility Fees

AIU has been in negotiations for a two-year bank facility in the amount of $635 million. Fees associated with this facility include one time arrangement and upfront fees (totaling $13.820 million, paid when the facility is put in place) and ongoing administrative agent and facility fees (totaling $5.256 million, paid quarterly after the facility is in place). AIU incurs these costs whether or not and regardless of the extent to which they borrow from the facility. Through AIU witnesses O'Bryan and Stafford, AIU initially recommended that the fees be recovered as Administrative and General (―A&G") expenses. AIU's initial proposal was that the pro forma adjustment include ongoing fees plus amortization of the one-time fees over the life of the facility allocated among the companies based on borrower sublimits.

Staff recommends the Commission reject the proposal to recover bank facility fees through A&G expenses rather than the cost of short-term debt. Specifically, Staff witness Phipps criticizes AIU's pro forma proposal, asserting that recovering the costs through a pro forma adjustment to operating expense assumes the upfront fees and facility fees are prudent and allocated properly for ratemaking purposes. She also asserts AIU's proposal incorrectly assigns AIU's non-utility costs and fails to recognize that the sublimit under the 2009 credit facility could effectively reduce AIU's sublimits to $500 million from $635 million. Additionally, Ms. Phipps asserts that each company allocates its costs between gas and electric delivery services using a labor cost allocator. Thus, she states that, unless AIU shows a clear relationship between credit facility usage and labor costs, the credit facility costs should be allocated amongst each utility's business operations based on investment, since the facility is a source of short-term debt. Finally, Ms. Phipps asserts the actual upfront and facility fees associated with the 2009 credit facilities are lower than estimates in the AIU proposal. She calculates one-time fees for AIU's proportion of the 2009 credit facilities as approximately $8.7 million and annual facility fees as $2.2 million.

For the purposes of this case, AIU accepts cost recovery via the capital structure. AIU agrees to accept Ms. Phipps' general methodology and remove bank facility fees from operating expenses and include them as a component of the capital structure consistent with Staff's recommended approach, but based on the calculation sponsored by Mr. O'Bryan. Cost recovery of this expense through AIU's capital structure is discussed below in this Order. For purposes of establishing rates in this proceeding, the Commission finds Staff's proposal to reflect bank facility fees as a component of capital structure to be reasonable and it is hereby approved.

5. Uncollectibles Expenses

AIU initially proposed pro forma adjustments to uncollectibles expense based upon a three-year average of actual values for net write-offs for 2007 and 2008 and budgeted net write-offs for 2009. Staff and IIEC both proposed adjustments to AIU's proposed uncollectibles expense based upon the 2006 through 2008 three-year average of net write-offs as compared to revenues. AIU subsequently proposed to substitute year-to-date actual September 2009 net write-offs and revenues for 2009 budgeted amounts. AIU notes that use of 2009 data to set rates more accurately reflects AIU's current uncollectibles expense, whereas use of 2006 actual data for uncollectibles expense ignores a fundamental change that took place in January 2007 for pricing of electric power supply and delivery service. Staff and IIEC accept AIU's proposal to calculate uncollectibles expense using actual 2007, 2008 and year-to-date September 2009 net write-offs. Staff also accepts AIU's proposal for the associated uncollectibles rate to be reflected in proposed uncollectibles riders approved in Docket No. 09-0399 on February 2, 2010. For purposes of setting rates in this proceeding, the Commission finds AIU's proposal to calculate uncollectible expense using actual 2007, 2008 and year-to-date September 2009 net write-offs to be reasonable and it is hereby approved.

6. Storm Expenses

AIU initially proposed to normalize its Storm Expense over a three-year period adjusted for inflation to reflect a trend in increased storm costs in recent years. Staff and AG/CUB proposed to normalize AIU‘s Storm Expense over a six-year period using expense data from 2003-2008 based on the Commission's use of a six-year average in Docket Nos. 07-0585 et al. (Cons.). AIU subsequently proposed to normalize Storm Expense using 2004 through year-to-date September 2009 data, instead of actual 2003 data, to better reflect the level of storm costs likely to be incurred during the period rates will be in effect. Staff does not object AIU‘s normalization approach as revised and accepts the Storm Expense adjustments as presented in Ameren Ex. 29.12. AG/CUB also finds AIU‘s normalization approach as revised to be reasonable. For purposes of this proceeding, the Commission finds AIU's revised proposal for calculating normalized Storm Expenses to be reasonable and it is hereby approved.

7. Automated Meter Reading Expense

Staff proposes an adjustment to remove certain conversion costs and purported non-recurring costs in the test year associated with AIU‘s Automated Meter Reading (―AMR”) upgrade. To reduce the number of contested issues, AIU accepts Staff‘s proposed adjustment to AMR expense. For purposes of this proceeding, the Commission finds Staff's proposed adjustment to AMR expense to be reasonable and it is hereby approved.

8. Smart Grid Costs

In its Order in Docket No. 07-0566, the Commission directed a collaborative workshop process be held to examine the smart grid modernization concept and its implementation. In that Order, the Commission stated that the purpose of the Illinois Statewide Smart Grid Collaborative ("ISSGC") is to develop a strategic plan to guide deployment of a smart grid in Illinois, including goals, functionalities, timelines, and analysis of costs and benefits, and to recommend policies to guide such deployment that the Commission can consider for adoption in a docketed proceeding. The Order directed AIU to participate in that workshop process. The Commission also stated in the Order that the least cost provisions require both that the chosen electric service be provided in the least cost manner and that the smart grid be at least cost, i.e., the components must be optimized to provide maximum benefits to consumers subject to competitive bids, and labor must be provided at competitive rates. Thus, the Commission wants to better understand how AIU‘s existing systems and technology can be adapted to support a statewide goal of complying with federal policy, embodied in the Energy Independence Security Act of 2007, Public Law No. 110-0140, directing states to consider smart grid initiatives. The Commission also wants to understand how implementation of smart grid technologies may alter costs and benefits considered when determining ―least cost.” In other words, the Commission recognizes AIU has already implemented facilities and technologies that will support smart grid efforts and that the cost/benefits framework may change to implement the final ISSGC vision.

In this proceeding, AIU initially sought to recover $1.3 million over a three-year period, which is AIU‘s share of the costs of the third-party facilitator and workshop facility rental costs. Staff witness Bridal, however, proposes an adjustment to smart grid costs, which results from a change in the scope of Phase 2 of the project and the removal of incremental costs that Staff does not believe are known and measurable. AIU accepts Staff‘s adjustment to smart grid costs, to minimize the number of contested issues in this case. For purposes of setting rates in this proceeding, the Commission finds Staff's proposed adjustment to smart grid costs to be reasonable and it is hereby approved.

9. Homer Works Headquarters Sale

Staff proposes an adjustment to update the AmerenCILCO electric Homer Works Headquarters Sale Adjustment to replace estimated amounts with actual amounts submitted by AIU in response to Staff data request RWB 6.06. AIU accepts Staff‘s proposed adjustment. The Commission finds Staff's proposed adjustment to be reasonable and it is hereby approved.

10. Social and Service Club Dues

Staff proposes an adjustment to remove all social and service club membership dues from AIU‘s recoverable operating expenses. AIU accepts Staff‘s proposed adjustment to remove these specific expenses from the revenue requirements. The Commission finds Staff's proposed adjustment to be reasonable and it is hereby approved.

11. Charitable Contributions

Staff proposed an adjustment to remove certain contributions to community and economic development organizations from AIU‘s revenue requirement, which Staff claims are amounts for items of a promotional or business nature that should be the responsibility of shareholders, not ratepayers. AIU objected to Staff‘s proposal to include in its proposed disallowance those items that were included in AIU‘s Schedule C-7, which are recorded to Account 426, a ―below-the-line” account, and thereby not included in AIU‘s requested revenue requirement. To reduce the number of contested issues, however, AIU accepts Staff‘s adjustment to reduce the amount of charitable contributions expense referenced in AIU‘s Schedule C-2.20. Staff accepts the adjustment to AIU‘s charitable contribution expense as presented by AIU in Ameren Ex. 29.13. For purposes of this proceeding, the Commission finds the agreement between

AIU and Staff regarding charitable contribution expenses to be reasonable and it is hereby approved.

12. Industry Association Dues

Staff proposed an adjustment to remove certain industry association dues attributable to lobbying activities. Staff witness Bridal calculated the adjustment by multiplying the 2008 industry association dues identified by AIU in its Schedules C-6.1 by a lobbying percentage developed from a 2007 invoice. After receiving 2008 invoice data in response to Staff data request RWB 19.01, Staff revised its adjustment for industry association dues. AIU agrees with Staff's proposal to calculate its adjustment based on 2008 test year invoice data, but notes that certain corrections need to be made based on Mr. Bridal's workpapers. Staff agrees with AIU's adjustments concerning industry association dues as presented in Ameren Ex. 51.12. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding industry association dues to be reasonable and it is hereby approved.

13. Advertising Expense

Staff proposed an adjustment to remove from AIU's revenue requirement all expenses recorded in Account 930, "Miscellaneous Advertising and General," or Account 930.1, "General Advertising Expenses," on the grounds that the amounts recorded in these accounts are promotional, political, institutional, or goodwill in nature. AIU accepted Staff's proposed adjustment in principle subject to certain modifications that Staff witness Bridal indicated he would make in response to additional information that AIU provided in response to data requests concerning these test year expenses. Staff now accepts the advertising expense adjustments as presented in Ameren Ex. 29.15. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding advertising expense to be reasonable and it is hereby approved.

14. Customer Service and Information Expenses

Staff proposed an adjustment to remove from AIU's revenue requirement certain customer service and information expenses, which Staff believed consisted mainly of purchases of clothing, promotional merchandise, and sponsorships that are promotional or goodwill in nature and not allowable under Section 9-225 of the Act. Staff witness Bridal, however, revised his adjustment for customer service and information expenses based on his review of specific transaction data provided by AIU. AIU accepts Mr. Bridal's revised adjustment for customer service and information expenses. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding customer service and information expenses to be reasonable and it is hereby approved.

15. Lobbying Expense

Staff proposes an adjustment to remove from AIU's revenue requirement for all electric utilities and AmerenIP gas operations lobbying expenses that were included in A&G expense accounts for the environmental services department personnel as identified in AIU's response to Staff data request RWB 18.01. AIU accepts Staff's proposed adjustment. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding lobbying expenses to be reasonable and it is hereby approved.

16. Rate Case Expense

Staff proposed to adjust rate case expense to account for the withdrawal and replacement of legal counsel in this proceeding and for the removal of the amortization of rate case expense from Docket Nos. 06-0070 through 06-0072 (Cons.). AIU accepts the adjustment for the removal of the amortization of rate case expense related to its prior rate case. AIU also accepts in principle Staff's adjustment to account for the withdrawal and replacement of legal counsel, but proposes that the amount of the adjustment be modified to include actual payments to prior counsel. AIU also updates its rate case expense to reflect actual, rather than estimated, amounts paid to experts and consultants and actual, rather than estimated, miscellaneous legal expenses. Staff accepts AIU's proposed changes to Staff's adjustment to rate case expense, and recommends that the Commission allow AIU to recover rate case expense in this proceeding in the amounts identified in Ameren Ex. 30.4. Staff also recommends, and AIU concurs, that the Commission expressly find that the amounts that AIU proposes to expend to compensate attorneys and technical experts to prepare and litigate this proceeding are just and reasonable pursuant to Section 9-229 of the Act.

The Commission finds the agreement between AIU and Staff regarding rate case expense to be reasonable and it is hereby approved. In addition, the Commission expressly finds that the amounts that AIU proposes to expend to compensate attorneys and technical experts to prepare and litigate this proceeding are just and reasonable pursuant to Section 9-229 of the Act. The Commission notes, however, that much of the written direct testimony for the six dockets at hand is identical. AIU could reduce rate case expense in its next rate case if it filed, to the extent possible/practical, one set of direct testimony supporting its initial tariff filing. A petition for a waiver of the requirements of 83 Ill. Adm. Code 286, "Submission of Rate Case Testimony," would be necessary. AIU is familiar with such efforts, however, given the filing of its petitions seeking waivers of other requirements of Part 285 prior to filing its tariffs leading to this proceeding. (See Docket Nos. 09-0270/09-0271 (Cons.))

17. Collateral Expense

AIU's gas operations must prepay or post collateral for certain services, due to limited access to unsecured credit. The collateral adjustment allows AIU to recover necessary costs associated with collateral posting for gas purchases. Test year gas collateral postings have been averaged over the 12-month test year from January through December 2008, and an interest rate is then applied to the average to be consistent with the method adopted by the Commission in Docket Nos. 07-0585 through 07-0590 (Cons.).

Staff witness Jones initially proposed a collateral expense adjustment to disallow interest expense associated with collateral posting for gas purchases. Ms. Jones argued that interest expense was no longer necessary and appropriate for recovery since AIU recently received a credit upgrading and now carried an investment-grade rating. AIU responded, however, that her assumption that AIU no longer incurs collateral expenses because its credit ratings were recently upgraded is incorrect. While it is true that investment grade credit ratings improve AIU's access to unsecured credit, AIU asserts that it has effective ratings at the lowest investment grade notch for the purposes of a very high percentage of contracts. Generally, the higher the effective rating, the greater the access to unsecured credit. Thus, while it now carries investment grade ratings, AIU states that it had positive collateral postings in place with its counterparties as of October 22, 2009. The amounts of collateral will vary according to the transactions executed and the applicable forward pricing curves. As long as collateral may be contractually required by its counterparties, AIU asserts that there will be a cost associated with posting such collateral. After reviewing AIU's response, Ms. Jones withdrew her proposed adjustment. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding collateral expense to be reasonable and it is hereby approved.

18. Company-Use Franchise Gas

Staff witness Seagle recommends that the Commission reduce AIU's request for its company-use and franchise gas expenses. Mr. Seagle states that the gas pricing that AIU used to value its requested franchise gas amounts resulted in an overstatement of gas prices on a going forward basis and recommends alternative pricing. AIU agrees with Mr. Seagle's proposal and updated the franchise gas pricing as Mr. Seagle recommends. Mr. Seagle also recommends that AIU provide rebuttal testimony that updates each of the three utility's company-use gas costs using the most recent gas pricing information available and normalizes the volumes. AIU agrees with Mr. Seagle's proposal and updated the company-use gas pricing and volumes as Mr. Seagle recommends. Staff agrees with the calculations AIU provided on rebuttal regarding AIU's company-use gas costs and franchise gas costs. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding company-use gas costs and franchise gas costs to be reasonable and it is hereby approved.

19. Real Estate Taxes

Staff proposes an adjustment for AmerenCIPS gas to remove amounts included in real estate taxes that Staff argues represent prior period adjustments, and not actual test year real estate taxes. To reduce the number of contested issues, AIU accepts

Staff's Schedule 4.14 adjustment for AmerenCIPS gas, as shown on Ameren Ex. 30.2, Schedule 1, Page 5 of 5, column (o). For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding real estate taxes to be reasonable and it is hereby approved.

20. Prior Period Hazardous Materials Adjustment Clause Costs

Staff proposes an adjustment for AmerenIP electric to remove what Staff believes are 2007 Hazardous Materials Adjustment Clause ("HMAC") costs from the revenue requirement. To reduce the number of contested issues, AIU accepts Staff's proposed adjustment to remove ―Prior Period HMAC costs" from the revenue requirement of AmerenIP. For purposes of this proceeding, the Commission finds the agreement between AIU and Staff regarding prior period HMAC costs to be reasonable and it is hereby approved.

B. Contested Operating Expense Issues

1. Tree Trimming

a. AIU Position

AIU states that consistent with the approach adopted by the Commission in the prior two electric delivery services rate cases, AIU proposes a pro forma adjustment to test year electric delivery services operating expenses to reflect 2010 budgeted tree trimming/vegetation management expenses. AIU says this adjustment is based on the current four-year trimming cycle applicable to all of AIU's electric operations. AIU claims its proposal does not include any cost for conversion to a ―no contact" zone approach – a conversion Staff suggests and that necessitates a more frequent trimming cycle to maintain ―no contact" for the entire service area. If the Commission requires AIU to convert to Staff's approach, AIU asserts that additional associated costs would need to be added to AIU's pro forma level of O&M expense for its Illinois electric delivery service operations.

AIU asserts that to ensure the reasonableness of the 2010 budget, AIU started with actual 2008 tree trimming expenses, reviewing the work performed in 2008 and related costs. AIU says this was compared to the work to be performed in 2010 and its projected costs, taking into account the four-year trim cycle requirements, Staff's expectations for reliability enhancement measures, and contracts with vegetation management contractors and local labor unions for negotiated wage increases. AIU states that in 2008, AIU's combined actual tree trimming expenses totaled $39.2 million, and the 2009 projected amount (based on 8 months of actual and 4 months of projected data) is $39.2 million. AIU says from this information, AIU's projects $39.3 million expected actual tree trimming expenses to be included in the combined revenue requirement.

AIU asserts that while trimming is planned for 24% of its total system in 2010, the percentages for each utility vary from 33% to 17% – based on number of circuits – or from 28% to 19% – based on number of circuit miles. According to Staff, this data shows that the amount of work and associated costs to maintain a four-year trim cycle within each company varies from year to year. Staff suggests that a company would not need to trim 28% of its circuit miles each year to maintain a four-year cycle, nor could a company that trims only 19% of its circuit miles each year maintain a four-year cycle. To address its concerns about the variability of such expenditures, Staff proposes to reduce AIU‘s tree trimming expenses. Staff determined its proposed adjustment by calculating an annual average expense amount using AIU‘s actual tree trimming expense for 2005 through June 30, 2009. AIU indicates that Staff's proposal allows only $34.6 million for trimming expenses, which is approximately $4.7 million less than what AIU expects to incur in 2010. Staff asserts that averaging costs over a period of time smoothes cost variances and provides a reasonable amount of tree trimming expense to include in the respective company‘s revenue requirement. Under AIU's proposal, Staff fears that some companies will receive too much revenue. Noting Staff's contention that each company may trim more or less than 25% in 2010 and still proposes to reduce tree trimming expenses for all three companies, AIU asserts that this is a mathematical impossibility if total trimming covers ¼ of the entire system. AIU contends that Staff's proposed adjustment should be rejected on arithmetic grounds alone.

AIU insists that it provided evidence to support its position that the amount of tree trimming expense projected in the 2010 budget is the appropriate amount of tree trimming expense for the 2008 historical test year. AIU says this evidence was provided in response to Staff data requests BCJ 12.01 through BCJ 12.08. AIU claims that the Superintendent of Vegetation Management for AIU sponsored several of these responses and asserts the responses accurately provide Staff with information regarding AIU‘s 2010 tree trimming activities. In AIU's view, Staff seems to disregard this evidence.

According to AIU, the viability of Staff‘s number depends, in great part, on Staff‘s restatement of costs dating back to 2005 in 2008 terms using a general inflator. AIU asserts that its number is based on what activity AIU knows it is going to be engaged in during 2010, using the costs that are applicable now, not five-year old data restated to 2008. AIU believes its adjustment is inherently superior to Staff‘s because it is fully rooted in reality and does not represent a "guess" at what AIU might be expected to spend on tree trimming in 2010.

AIU also insists that its proposed tree trimming expense level is not unreasonable within the four-year trim cycle. AIU says the 2010 number is consistent with the 2008 and 2009 levels. AIU states that Staff proposes reducing the 2010 level because, apparently, the 2008, 2009, and 2010 levels are too high in Staff‘s judgment. AIU notes that Staff does not claim that AIU is doing too much trimming. Rather, Staff claims that over four years the level of activity will average out to the number which Staff proposes.

In AIU's view, Staff's approach is reckless, and its "faux-precision" is no salvation. AIU argues that Staff puts system integrity at risk by, in effect, directing AIU to spend less on tree trimming this year because Staff believes that its restatement of old spending levels to 2008 dollars produces a figure that its sufficient. AIU believes this is unsound regulatory policy, and should be rejected by the Commission. If the Commission adopts Staff's proposal, AIU claims it will need to synchronize expenditures to rate recovery by spending $4.7 million less than the amount needed for tree trimming functions in 2010 and beyond. According to AIU, Staff's recommendation will be less than required to achieve the four-year trimming cycle across all of AIU's service areas.

AIU avers that both the Commission and Staff recognize the importance of a four-year trim cycle, as evidenced by the Commission's acceptance of Staff's repeated recommendations in its annual reliability assessment reports. AIU states that the Illinois Commerce Commission Assessment of AmerenIP's Reliability Report and Reliability Performance for Calendar Year 2007, which the Commission accepted, recommended AmerenIP ―should do whatever is necessary to maintain a four-year (minimum) tree trimming cycle that is also in compliance with 2002 NESC Rule 218 throughout its service territory." Additionally, AIU says Staff's findings in the February 14, 2008 Staff Report to the Commission, on the Assessment of the Ameren Illinois Electric Utilities' Reliability for 2006, included similar recommendations for all three utilities. AIU relates that in Docket No. 00-0699, the Commission ordered CILCO to follow a four-year trim cycle, and AmerenIP and AmerenCIPS voluntarily committed to the Commission to do the same. Thus, if the Commission adopts Staff's position, AmerenCILCO must petition the Commission to alter its four-year cycle requirement.

In addition, if Staff's adjustment is adopted, AIU claims it will not be able to continue reliability-enhancement tree trimming programs. AIU asserts it will trim fewer trees, and the likelihood for less reliable service will increase. AIU says although $4.7 million is a relatively small percentage of the total revenue request, it can have a significant impact. AIU believes Staff's proposed tree trimming adjustment is unsupported and should be rejected.

b. Staff Position

Staff proposed an adjustment to normalize tree trimming expense in the test year based on the actual amount of tree trimming expense incurred by each utility for the time period January 2005 through June 2009. Staff acknowledges that it presented no testimony regarding the appropriate amount of tree trimming or the time period over which it is to be done. In Staff's view, the only issue regarding tree trimming is how much cost is to be included in the revenue requirement. Staff says AIU's vegetation management programs are based on maintaining a four-year trim cycle, but the amount of work and associated costs to maintain that cycle vary from year to year. Staff states that while trimming is planned for 24% of the total AIU system in 2010, the percentages for each AIU vary, as discussed above. Staff suggests that the average of costs incurred by each utility over a period of time smoothes the cost variances and provides a reasonable amount of tree trimming expense to include in the respective revenue requirements.

AIU claims that Staff's recommended level of expenditure for tree trimming will be less than the amounts required to cover AIU's costs to achieve a four-year tree trimming cycle across its service territories. Staff says AIU cites compliance with four-year trim cycles, the inclusion of expanded reliability enhancement programs such as —cycle buster" and —prescriptive tree trimming," and wage increases as the reasons its proposed test year tree trimming expense exceeds historical average costs. Staff argues that AIU has been on four-year trim cycles since 2004; mid-cycle patrols began in 2004 for AmerenCILCO and AmerenCIPS and 2005 for AmerenIP; and prescriptive trimming began in October 2006 for all three companies. Staff claims AIU made no claim that the amount spent for tree trimming in the period from which Staff calculated an annual average, updated to 2008 dollars, was not sufficient for each utility to meet its trimming obligations.

Staff indicates that AIU takes exception to the historical time period that it used to calculate an average annual amount for tree trimming expense on the basis that it is too far removed from the time that rates will become effective. In Staff's view, the lag that exists between historical periods and the time rates go into effect is a normal consequence of filing an historical test year, which is the type of test year AIU used. Staff suggests that a utility wishing to avoid the lag can choose to file a future test year. But even if AIU had filed a future test year, Staff adds that the trimming expense in each utility's 2010 budget is not assumed to be the appropriate amount to include in its revenue requirement. Staff states that a future test year has its own set of requirements, including review by an independent accounting firm of the assumptions on which the numbers are based.

According to Staff, AIU attempts to compensate for the lag with pro forma adjustments based on the 2010 tree trimming budget for each utility. Regarding pro forma adjustments, Section 287.40 provides as follows:

> These adjustments shall reflect changes affecting the ratepayers . . . where such changes occurred during the selected historical test year or are reasonably certain to occur subsequent to the historical test year within 12 months after the filing date of the tariffs and where the amounts of the changes are determinable.

Staff states that while a budget may reflect an expected change in operating results, it does not reflect a known and measureable change in operating results. Staff believes that AIU's adjustments do not meet the —known and measurable" criteria and are inappropriate for pro forma adjustments to a historical test year. For ratemaking purposes, Staff believes that the average annual amount of tree trimming expense calculated for each utility approximates a more normal level of expense than does the amount spent in any one year and should be adopted by the Commission.

With regard to AIU's arithmetic error claim, Staff denies that its adjustment to reduce tree trimming expense for all three companies is mathematically impossible. Staff asserts that it is possible to make such an adjustment when the annual historical average to maintain a four-year tree trimming cycle at each utility, calculated for the period January 2005 through June 2009, is less than the pro forma adjustment for the respective utility. Staff says the average of costs incurred by each utility over a period of time smoothes the cost variances and provides a reasonable amount of tree trimming expense to include in each respective revenue requirement. (Staff Reply Brief at 22)

c. IBEW Position

IBEW agrees with AIU that a reduction of $4.7 million in the amount spent on tree trimming will leave an inadequate amount to maintain a four-year tree trimming cycle and may contribute to less reliable service. IBEW echoes AIU's claim that although the reduction appears to be small compared to the entire requested rate increase, it can still have a significant impact on AIU operations as well as IBEW members and the Illinois workforce. According to IBEW, the issue of tree trimming is exemplary of the negative effect that an inadequate rate increase would have on not only customer reliability, but also the Illinois workforce. If rates are insufficient to recover costs, IBEW states that AIU would need to reduce operating and maintenance expenditures, likely including reductions in contractors and deferral of maintenance. IBEW argues that such reductions would have a negative impact on customer service, including a reduction in tree trimming. Without recovery of sufficient revenue to maintain the minimum four-year cycle recommended by the Commission, IBEW complains that fewer of the skilled union contractors which perform tree trimming could be hired. IBEW says this loss of jobs would harm the Illinois workforce.

d. Commission Conclusion

AIU proposes a pro forma adjustment to the historical test year tree trimming expenses which amounts to a total of $39.3 million in operating expenses for all three electric utilities' vegetation management efforts. Staff opposes AIU's adjustment and instead recommends basing trimming expenses on the average annual trimming expenses for the period January 1, 2005 through June 30, 2009. Staff's proposal results in a combined reduction to the three utilities' rate bases of approximately $4.7 million.

From Staff Ex. 3.0, the Commission understands that actual tree trimming expenses incurred in the years 2005 through 2008 as well as during the first six months of 2009 are as follows:

Actual Tree Trimming Expenses (in thousands of dollars)							
	AmerenCILCO		AmerenCIPS		AmerenIP		Total
2005	3,844		10,584		14,574		29,002
2006	5,372		9,099		14,597		29,068

2007	4,663		13,652		15,483		33,798
2008	4,919		17,877		16,386		39,182
2009	2,544		7,356		8,354		18,254

While some variability exists in the annual expenses, the Commission is hesitant to label the expenditures "volatile" for any of the three utilities. What variation that does exist can be characterized as a generally modest upward trend overall. But given that the Commission and Staff in the engineering department have been urging the utilities to improve their tree trimming and vegetation management practices in an effort to improve reliability, this trend is not surprising.[9] AIU's proposed expenses appear to continue this trend overall. The AIU and Staff proposed tree trimming expenses for each utility are as follows:

Proposed Tree Trimming Expenses (in thousands of dollars)							
	AmerenCILCO		AmerenCIPS		AmerenIP		Total
AIU	5,512		15,978		17,783		39,273
Staff	4,949		13,504		16,097		34,550

Given this history, it is not clear to the Commission that Staff's proposed averaging is necessary or appropriate. AIU's total proposed tree trimming expenses for the three electric utilities is essentially the same as was actually incurred in the 2008 test year. It appears that AIU's proposed pro forma adjustment to trimming expenses is primarily intended to reallocate expenses among the three utilities so that the level of expenses at each of utility matches more closely the expected expenditures in 2010 rather than the actual expenditures in 2008. The pro forma adjustment does not increase total tree trimming expenditures for the utilities in any significant way. As a result, the Commission rejects Staff's averaging proposal and accepts AIU's proposed pro forma adjustment to trimming expenses.

2. Incentive Compensation Expenses

a. Staff Position

Staff indicates that AIU accepts the portion of Staff‘s proposed adjustment to incentive compensation expenses to remove previously disallowed capitalized incentive compensation costs from the test year rate base proposed by AIU. Staff says that AIU continues to oppose Staff's proposed adjustments to remove costs associated with key performance indicators (“KPIs”) for O&M Budget Compliance and Capital Budget Compliance as well as the proposal to disallow costs which Staff believes have not been shown to result in net benefit to ratepayers.

[9] This observation should not be taken by AIU as authorization to propose even higher vegetation management expenses in future rate cases without adequate support. Any proposed expenditures must be reasonable and sufficiently justified by AIU.

Staff says the Commission did not allow costs associated with KPIs related to budget compliance in the prior rate cases and complains that AIU relies on the same argument in this case. AIU says the establishment and focus on budget targets provides benefits to ratepayers by setting a goal for managing overall expenditures for projects and services within a defined time period. AIU claims cost management/cost control is beneficial to customers to assure dollar resources are spent on priority initiatives and within the desired timeframes. AIU asserts that this helps assure that customers receive quality service in the most cost-effective manner.

Staff believes that AIU's argument merely restates what the ratepayers already expect from their utility, quality service in the most cost-effective manner. Staff claims AIU fails to acknowledge that cost management/cost control is of equal, if not greater, benefit to its shareholders, thus making it more in line with the KPI related to earnings per share ("EPS") which AIU has already removed from its revenue requirements. In Staff's view, AIU failed to demonstrate how the budget compliance KPIs is based on anything other than financially related goals. Staff insists that the costs related to those KPIs should be disallowed from recovery in the revenue requirement.

Staff says AIU offers Ameren Ex. 42.1 as further information demonstrating the ratepayer benefits of the operational goals of AIU's incentive plans. Staff complains that the exhibit merely describes what the KPIs are designed to do; the exhibit does not reflect the outcome or results of the performance of the goals, making it impossible to determine any benefit the ratepayers might gain from the goals being met. Even though the targeted goal might be reached, Staff argues that the expected outcome or benefit may not have been achieved or the benefit may in fact be less than anticipated when the goal was established. Staff contends that in response to Staff discovery, AIU was unable to provide any benefit associated with the performance of those goals.

Staff agrees that not all benefits that may be achieved are tied to financial measurement. Staff says it identified certain other KPIs for which it is proposing to allow cost recovery. Staff is proposing to disallow all amounts allocated from AMS to AIU for incentive compensation since Staff believes a portion of those costs are tied to financial goals and AIU did not demonstrate customer benefit resulting from the remainder of the goals.

According to Staff, AIU argues that because the record in its prior rate proceedings indicated that it was reasonable to pass along certain portions of incentive compensation expense to its customers for recovery through rates, similar costs should be allowed for recovery regardless of the record in the current proceedings. Staff contends, however, that the more developed record in the current proceedings demonstrates that AIU has not met the standard set by the Commission for recovery of incentive compensation expense through base rates.

Staff says AIU suggests that information regarding customer benefit was provided for both of the AIU incentive compensation plans as well as the AMS incentive compensation plans. Staff asserts that information included in Ameren Ex. 42.1 was limited to the incentive plans for AIU and no comparable information was provided for the AMS plans. Staff insists that no showing of customer benefit was made specific to the AMS plans.

b. AIU Position

The Commission, AIU avers, has a policy of permitting recovery of incentive compensation expense where the utility has demonstrated that its incentive compensation plans result in tangible benefits for ratepayers. AIU says that in a recent decision, the Commission clarified the standard when it stated that, with respect to the formulation for recovering incentive compensation, ―[t]he main and guiding criterion is that the expense be prudent, reasonable and operate in a way to benefit the utility‘s customers.” (AIU Initial Brief at 73, citing Docket No. 07-0241, Order at 66)

In AIU‘s prior rate case, AIU says the Commission approved recovery of 50% of AIU‘s requested incentive compensation expense, based on the determination that incentive plans related to certain operational goals (safety, reliability and customer service) provided direct, meaningful benefits to ratepayers, and payouts for these goals were not dependent upon meeting financial targets. AIU asserts that the Commission considered evidence from AIU in that case regarding the operational and individual goals of its incentive compensation plans and how the metrics benefited AIU customers by enhancing service, increasing service reliability, and/or increasing the efficiency of operations. AIU claims it has provided more extensive information in this case regarding ratepayer benefits of incentive plan goals. AIU says the Commission did not require in the prior case that AIU demonstrate whether the targeted goals were attained, whether the expected outcome or benefit was actually achieved, or whether the actual benefit was less than anticipated when the goal was established.

AIU insists it has satisfied the above standards by providing extensive information relating the customer benefits of the incentive plans‘ operational goals in testimony and discovery responses. In light of the determination in AIU‘s prior case, it is AIU‘s position that a showing that AIU has incentive compensation plans in place that are ―related to” areas such as safety, customer service, and reliability that benefit ratepayers is sufficient to obtain recovery of incentive compensation expense. AIU claims it has provided even more extensive information demonstrating that all its KPIs provide ratepayer benefits.

AIU says it seeks recovery of the portions of incentive compensation expense related to operational goals and that expenses related to EPS financial goals were removed from its request for recovery. AIU contends that incentive compensation is a common and necessary component of the total compensation package for employees in the electric and gas utility industry. AIU asserts that its incentive plans focus primarily on awarding employees based on their performance relative to operational goals that benefit the ratepayer (e.g., customer service, reliability, safety, operational efficiency, etc.) AIU argues that by designing a market-competitive incentive plan that rewards employees for achieving operational goals that they are most able to influence and control, AIU is able to attract and retain the most qualified talent in the electric and gas utility industry while motivating the highest level of performance in key areas that have a direct, positive impact benefiting the ratepayer.

AIU states that employees participate in one of four annual incentive compensation plans: the Executive Incentive Plan for officers (—EIP-O”), which applies to all officers within AIU, the Executive Incentive Plan for managers and directors (—EIP-M”), which applies to all members of the Ameren Leadership Team (—ALT”) with the exception of officers, the Ameren Management Incentive Plan (—AMIP”), which applies to AIU‘s professionals and supervisors (excluding ALT and bargaining unit employees), or the Ameren Incentive Plan (—AIP”), which applies to employees who are represented by a bargaining unit. AIU asserts that these plans are based on individual and operational goals designed to provide tangible benefits to Illinois ratepayers. AIU says these same plans apply to both AIU and to AMS. AIU believes that recovery of requested incentive compensation expense for AMS should be permitted.

AIU acknowledges that a certain percentage of the EIP-O and EIP-M is funded based on financial performance. AIU says costs related to these financial goals have been removed from AIU‘s requested incentive compensation expense. AIU contends that the remaining goals for these programs are based on operational performance as measured by incentive KPIs. AIU asserts that incentive KPIs generally represent goals related to important operational issues such as safety, reliability, customer satisfaction, and operational excellence. AIU states that the AMIP is funded based on achievement of pre-defined incentive compensation KPIs. AIU claims these KPIs focus plan participants on key operational metrics such as safety, reliability, cost control, and customer satisfaction. AIU says the AIP is funded and paid 100% based on incentive KPI performance. According to AIU, the incentive KPIs are designed to focus employees on important operational goals that they can influence. AIU says incentive compensation paid under the AIP does not include the O&M Budget Compliance and/or Capital Budget Compliance measures.

AIU complains that despite the extensive information provided to Staff regarding AIU‘s incentive compensation expense, in Direct Testimony Staff proposed to disallow all test year incentive compensation expense, both the expense associated with O&M Budget Compliance and Capital Budget Compliance measures, as well as other expense for which Staff claims AIU failed to —quantify” ratepayer benefits or otherwise calculate the —net benefits” to customers. AIU says Staff claimed that AIU was unable to identify any benefit to customers of employee attainment of the operational goals on the 2008 Scorecards, based on its response to a Staff data request.

AIU says it provided further information in the Rebuttal Testimony of an AIU witness that it believes demonstrated that the operational goals associated with AIU‘s incentive compensation plans provide real benefits to customers. AIU asserts that Ameren Ex. 42.1 provides a detailed summary of the ratepayer benefits of significant KPIs. For example, AIU asserts that the —Meet Gas Leak Response Objectives” tracks response performance to customer initiated calls to AIU where a gas odor is present.

AIU indicates it responds to and investigates every gas leak call that is received. AIU says the accepted criteria for a prompt response are ―as soon as possible but no more than an hour." AIU claims it has gone beyond the accepted criteria and established additional KPI criteria: responding to each leak in an average of less than 25 minutes. In 2007, AIU says it responded to over 34,000 gas leaks, and within one hour 99.8% of the time and the average response time was about 23.4 minutes. AIU states that in 2006, it responded to 99.5% of all gas leaks within one hour and 24.2 minutes for an average response. AIU insists that on this KPI not only are there ratepayer benefits but there is an improvement in performance.

AIU also argues that KPIs for O&M Budget Compliance and Capital Budget Compliance provide ratepayer benefits in the EIP-M and the AMIP. According to AIU, the establishment and focus on budget targets provides benefits to ratepayers by setting a goal for managing overall expenditures for projects and services within a defined period of time. AIU claims that cost management/cost control is beneficial to customers to assure dollar resources are spent on priority initiatives and within the desired timeframe. AIU believes this helps ensure that customers receive quality service in the most cost-effective manner. In AIU's view, a focus on budget/cost control helps reinforce AIUs' culture of cost management and finding new ways to reduce expenditures while improving service and customer satisfaction. AIU insists that ratepayers benefit from this.

While the Commission has previously disallowed recovery of incentive compensation related to financial goals or triggers, AIU argues that O&M Budget Compliance and Capital Budget Compliance KPIs are not related to financial goals. According to AIU, the Commission has previously approved the recovery of incentive compensation expense related to goals of reducing O&M and capital expenses, in Docket No. 05-0597. AIU says the Commission found that focusing on the funding measure that rewards employees for reducing O&M and capital expenses meets the Commission's standard of reducing expenses and creating greater efficiencies in operations. AIU says the Commission found that lowering O&M expenses, all else being equal, has the obvious effect of reducing the expenses to be recovered in future rate cases. AIU believes it has demonstrated that the costs associated with O&M Budget Compliance and Capital Budget Compliance provide such benefits. Consistent with the Commission's ruling in Docket No. 05-0597, AIU asserts that recovery of these expenses should be allowed.

AIU says the Commission most recently confirmed that incentive compensation goals need only be designed or expected to achieve certain goals in its recent decision in a Peoples rate case Docket No. 07-0241. AIU asserts that in that case, Staff proposed to disallow incentive compensation expense related to goals ―unlikely to be achieved." AIU says the Commission rejected Staff's proposal, even though the goals might not have been achieved in the past. AIU says the Commission found that Staff's position does not recognize that the nature of incentive compensation plant is such that there is no guarantee that the goals will be met and the compensation paid to employees. AIU believes the Commission's decision in the Peoples rate case further illustrates that quantifying the actual performance and resulting benefits of incentive compensation goals is not a prerequisite to recovery of incentive compensation expense.

c. AG/CUB Position

AG/CUB says the Commission has an established policy of eliminating incentive compensation program costs unless the utility can demonstrate that the goals employees are expected to achieve would benefit ratepayers, such as the improvement of service quality, reliability, public safety, reducing absenteeism, and cost containment. AG/CUB avers that incentive compensation based on financial goals such as maximizing profitability and growth, increasing EPS, or increasing return on equity ("ROE") is beneficial only to shareholders, and not properly recoverable from ratepayers.

In AIU's last rate cases, AG/CUB indicates the Commission —allowed [AIU] to include in operating expense 50% of the total cost of its incentive compensation expense because the Commission believes that portion provides direct, meaningful benefits to ratepayers and payouts are not dependent upon meeting financial targets that are primarily beneficial to shareholders." (AG/CUB Initial Brief at 21-22, citing Docket No. 07-0585 et al. (Cons.), Order at 108) In the second most recent AIU rate proceeding, the Commission had found that the AIU incentive compensation funding measures all relied on EPS targets and disallowed the entire test year compensation from the revenue requirements. (AG/CUB I B at 22, citing Docket Nos. 06-0070/0071/0072 (Cons.), Order at 72)

In the present case, Staff recommends the Commission exclude those incentive compensation costs that do not result in net benefits to consumers. AG/CUB adds that AIU's defense of its incentive compensation expense merely restates what the ratepayers already expect from their utility, quality service in the most cost-effective manner. With regard to the costs which have not been shown to result in net benefits to customers, including all of the amounts allocated from AMS, AG/CUB allege that Staff demonstrates why the information provided by AIU falls short of providing the support necessary to include those costs in AIU's revenue requirements. AG/CUB argues that any incentive compensation cost that has not been shown to result in a net benefit to ratepayers must be disallowed. AG/CUB asserts that incentive compensation related to O&M Budget Compliance and Capital Budget Compliance KPIs should be eliminated from AIU's revenue requirements.

d. IBEW Position

According to IBEW, incentive compensation under the AIU incentive plans not only provides benefits to ratepayers, but also fosters a healthy workforce, and should therefore be recoverable. IBEW indicates that AIU's AIP applies to employees that it represents. IBEW contends that the AIP is 100% based on performance as measured by incentive KPIs, which focus employees on important operational goals that they can influence, including safety, reliability, customer satisfaction, and operational excellence. IBEW states further that a number of the KPIs, simply by their goal targets, illustrate a customer benefit. IBEW claims the remainder of the KPIs relate to the creation of efficiencies in operations and expenses. AIU employees that it represents, IBEW continues, rely on incentive compensation as part of their pay. If AIU discontinues portions of the incentive compensation package in order to match its costs to Staff's proposed recovery, IBEW says employees would essentially be taking a pay cut, causing further harm to the Illinois workforce.

e. Commission Conclusion

Every AIU employee participates in one of four annual incentive compensation plans. AIU seeks to recover $12,119,701 in incentive compensation plan expenses for both the operating utilities and AMS. Staff proposes adjustments to remove costs associated with KPIs for O&M Budget Compliance and Capital Budget Compliance as well as to disallow costs which Staff believes have not been shown to result in net benefit to ratepayers. Staff's adjustments disallow approximately $9.1 million from AIU's requested expense amount. AG/CUB supports Staff's proposed adjustment while AIU and IBEW oppose the proposal.

The Commission has expended a significant amount of time reviewing the record on this issue. Staff is correct that in AIU's last rate case, the Commission did not authorize AIU to recover from customers certain incentive compensation costs, including costs associated with O&M Budget Compliance and Capital Budget Compliance. The Commission continues to believe that such costs should not be borne by ratepayers because they primarily benefit shareholders.

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. The difficulty is in discerning the "net," in other words, it is not always clear that the benefits outweigh the costs. For example, if a safety KPI is met and no injuries have occurred on the job, it is difficult to say at what point the benefits of no injured workers began to outweigh the costs of the safety initiative.

In parsing through the voluminous record on this issue, and with the help of the parties' Briefs on Exceptions, the Commission has been able to identify ten specific KPI areas from the 2008 test year that Staff recommends disallowing: 1) O&M Budget Compliance, 2) Capital Budget Compliance, 3) Occupational Safety and Health Administration ("OSHA") Recordable Injuries, 4) Electric Reliability Program Objectives, 5) Energy Efficiency, 6) Gas Leak Response Objectives, 7) Safety: Lost Work Day

Away, 8) Gas Compliance, 9) Real Time Pricing ("RTP") Meter Installs, and 10) Meter Test Completion. Ameren Ex. 42.1 identifies and describes the KPIs for the 2008 test year. Schedule 7 within Ameren Ex. 51.7 Third Revised attached to Ameren Ex. 51.0 Second Revised reflects the dollar amounts associated with each KPI for the 2008 test year.

As indicated above, the Commission continues to believe that incentive compensation expenses associated with O&M Budget Compliance and Capital Budget Compliance should not be recovered from ratepayers. Of the remaining eight KPI areas that Staff proposes to disallow, the Commission agrees with four of the proposed disallowances. Specifically, the Commission is not persuaded that the benefits to ratepayers outweigh the costs associated with the Electric Reliability Program Objectives, Safety: Lost Work Day Away, RTP Meter Installs, and Meter Test Completion KPIs. AIU seeks to recover $308,144 for the Electric Reliability Program Objectives KPI. AIU describes this KPI as including, among other things, correcting NESC violations. Given its concerns about the NESC violations, the Commission is not inclined to pass on to ratepayers incentive compensation expenses associated with corrections that should not even be necessary. Because the Commission can not discern how much of this KPI expense is attributable to correcting NESC violations, the total amount for this KPI is disallowed. With regard to the Safety: Lost Work Day Away KPI, the Commission finds this KPI very similar to, if not redundant, to the OSHA Recordable Injuries KPI. It is up to AIU to decide if it wishes to establish similar goals within its incentive compensation plans; the Commission, however, sees no need to impose on ratepayers expenses that are arguably redundant and for which they do not appear to receive any additional benefit. The disallowance for this KPI amounts to $250,826. With regard to the RTP Meter Installs and Meter Test Completion KPIs, the Commission finds the record to be lacking sufficient evidence to conclude that the benefits to ratepayers outweigh the costs. Accordingly, the Commission finds that $24,042 and $36,063 for the RTP Meter Installs and Meter Test Completion KPIs, respectively, should be disallowed.

Those KPI areas for which the Commission finds recovery of incentive compensation expenses appropriate in this proceeding despite Staff's objections include OSHA Recordable Injuries, Energy Efficiency, Gas Leak Response Objectives, and Gas Compliance. As indicated above, evaluating at what point the benefits of injury prevention began to outweigh the costs of a safety initiative is difficult to say. The incentive compensation expenses associated with the OSHA Recordable Injuries ($1,268,510), Gas Leak Response Objectives ($1,272,685), and Gas Compliance ($59,575) KPIs, however, do not appear unreasonable in light of the health and safety benefits for employees and customers. Regarding the Energy Efficiency KPI, the Commission is persuaded that the long term benefits attributable to this KPI outweigh the $628,865 expense. Collectively, these "allowed" KPIs amount to $3,229,635 for all three operating utilities.

The remaining incentive compensation expenses that AIU seeks to recover amount to $4,332,686 associated with AMS' KPIs. After reviewing the voluminous record on this issue, it is not entirely clear what the specific KPIs for AMS are. Even if that information was available, the record lacks evidence as to how the $4,332,686 is broken down among the AMS KPIs. In the absence of useful information, the Commission is compelled to accept Staff's proposed adjustment regarding the AMS KPIs. Accordingly, the Commission finds that AIU may recover the $2,995,008 in incentive compensation expenses to which no one objects and the Commission finds reasonable and the $3,229,635 which the Commission has allowed over Staff's objection. This total of $6,224,643 represents approximately 51% of the amount requested by AIU, which the Commission notes is similar to the 50% allowed in AIU's last rate case. The Commission adds that nothing in this conclusion prevents AIU from offering incentive compensation plans; AIU is simply limited in its means of recovering the expenses for such.

Also of some concern to the Commission is the record's silence on why AIU's KPIs for 2008 and 2009 are different. Nor is it clear whether and to what extent KPIs may change in the future. It would behoove AIU to settle on a set of KPIs. If alterations are necessary, an explanation should appear in AIU's testimony in future rate cases.

The Commission also questions whether AIU fully appreciates that cost management/cost control efforts benefit shareholders as well as ratepayers, as Staff suggests. KPIs which appear to benefit ratepayers by reducing costs should not necessarily be allocated entirely to ratepayers for cost recovery purposes. AIU should consider the benefits that accrue to shareholders as well under cost management/cost control measures and is expected to reflect such consideration in future rate cases.

3. Pension, OPEB, and Major Medical Expenses

a. AIU Position

AIU‘s cost of service includes pension and OPEB expenses for current and former employees. AIU claims that the financial meltdown that occurred late in 2008 caused a significant decline in plan assets used to pay benefits, resulting in an increase in pension and OPEB expense beginning in 2009. Because actual 2008 pension and OPEB expense is not representative of either actual 2009 expense or expense that will be incurred in 2010 when new rates go into effect, AIU proposes to establish test year expense based on twelve months of actual expense for the period October 2008 through September 2009. AIU asserts that the use of actual expense amounts for the year following the test year is consistent with the treatment of pension and benefits expense in AIU‘s two most recent rate proceedings.

Staff argues that pension and benefits expense for the 12-month period ending September 30, 2009 is not known and measurable, and therefore proposes to establish pension and benefits expense based on calendar year 2008 data. According to AIU, Staff takes this position notwithstanding Staff witness Ebrey‘s acknowledgement that the value of securities used to fund AIU‘s pension and OPEB plans decreased significantly in 2008, resulting in an increased level of pension and benefits expense that began to be recognized in 2009. According to AIU, Staff states that the entries for pension costs for the months during 2009 are based on the reports prepared by Towers Perrin in January 2009 and July 2009. Staff says the actual pension cost for the year ending December 31, 2009 and the Employer Contribution for the Plan Year beginning January 1, 2009 will not be determined until the year end 2009 actuarial study has been completed, after the record in these proceedings will be marked heard and taken. AIU says Staff‘s adjustment for pension and benefits expense would reduce AIU‘s aggregate revenue requirement by almost $16 million.

AIU believes Staff‘s proposed adjustment reflects a misunderstanding of the accounting for pension and benefits expense and should be rejected. AIU states that the calculation of pension and OPEB expense is determined by Accounting Standards Certifications 715-30 and 715-60 ("ASC 715"), formerly FAS 87 and 106, respectively. According to AIU, under ASC 715, employee census data, plan asset values, and financial market conditions as of the last day of the prior year are used to develop pension and OPEB expense for the following year. AIU claims that 2009 pension and OPEB expense is based on a valuation using data as of December 31, 2008. AIU says the year-end financial data for the prior year is used to prepare quarterly reports that AIU uses to record pension and OPEB expense for the following year. AIU states that the first quarter report is based on estimated employee census data while actual census data is used for the second quarter report. AIU says that third and fourth quarter reports are also based entirely on actual data.

AIU contends that when the valuation report is completed for the second quarter of each year, the pension expense for that year is already known and measurable. AIU asserts that expense levels will not vary from the second quarter valuation report to the final valuation report unless there is a —significant event,” as determined by ASC 715, such as a material workforce reduction or acceleration of benefits. According to AIU, the last —significant event” that occurred for AIU was the 2004 acquisition of IP. AIU says no significant events have occurred since, nor are any expected.

Considering how pension and OPEB expense are accounted for under ASC 715, AIU insists that Staff‘s claim that these expenses will not be determined until the year end 2009 actuarial study has been completed is not correct. AIU argues that the July 1, 2009 Towers Perrin report (Ameren Ex. 38.2) provides a known and measurable level of pension and OPEB expense that has been incurred through September 2009. AIU reiterates that there were no —significant events” in the third quarter of 2009, and asserts that even if a significant event occurred in the fourth quarter, such an event would not affect pension and OPEB expense for prior quarters.

In AIU's view, the July 2009 valuation report provides reliable, probative evidence of pension and OPEB expense booked in 2009 through September. AIU states that the amounts provided in this report are the same amounts recorded on the books of AIU. AIU suggests that in determining the appropriateness of any pro forma adjustment, all the evidence should be considered, including recent actual data where available. AIU claims that Staff assumes that the amounts booked through September 30, 2009 could change when the final actuarial report is issued. AIU insists that no reason, no rationale, and no record evidence support this assumption. AIU states that the amounts booked through September 30, 2009 will not change when the final report is issued in early 2010. AIU also indicates that expenses through September 2009 have already been incurred and recorded on the books of AIU and will not change. AIU also says that pension expense for the 12-month period ending in September 2009 significantly exceeds 2008 expenses, by $16 million. If AIU‘s rates do not reflect this increased level of expense, AIU insists it will fail to recover its authorized ROR.

AIU claims that the amounts reflected in its books to support the pro forma adjustment are based on the July report, not the January report. More importantly, in AIU's view, the Towers Perrin July 2009 report reflects known and measurable data for pension and OPEB expense as required by the relevant accounting standard. AIU maintains that as there were no significant events in 2009, this report contains final pension and OPEB expense amounts for AIU through September 30, 2009. AIU argues that because the July 2009 report reflects known and measurable data, the pro forma adjustment based on this data is equally known and measurable. AIU says it bears repeating that the pro forma adjustment is based on amounts actually recorded in AIU‘s books, not budgeted amounts as initially proposed in Direct Testimony.

Staff argues that the changes to AIU‘s headcount as a result of workforce reductions occurring in the fourth quarter of 2009 are not reflected in the amounts recorded on AIU‘s books as of September 30, 2009. AIU states that this argument fails because the fourth quarter workforce reductions and other events occurring after the fourth quarter can not impact the calculation of pension and OPEB expense through September 30, 2009. AIU also asserts that such events will not cause the fourth quarter 2009 expense accruals to vary from those provided in the July 2009 valuation report by Towers Perin. According to AIU, neither the workforce reductions nor the market meltdown of 2008 constituted a significant event, as defined by the relevant accounting standard, which could impact expense accruals for the fourth quarter of 2009.

AIU disputes Staff's claim that AIU has selectively picked significant expense items and proposes to update them to the most current amounts recorded on the utility books. AIU says its proposal to establish pension and OPEB expense based on the 12 months ending September 30, 2009 is well within the period for pro forma adjustments allowed by Section 287.40 or Part 287. AIU indicates that Staff itself has proposed a number of adjustments based on 2009 actual data. AIU claims that in its last two rate proceedings, pension and OPEB expense was based on data for the year following the test year. AIU believes its proposal does not violate test year principles.

AIU argues that Staff‘s real reluctance to adopt AIU‘s proposal seems to stem from the fact that AIU does not propose to establish pension and OPEB expense based on the ―final" 2009 actuarial report that will be issued by February 1, 2010. AIU says that Staff distinguishes AIU‘s proposed treatment of this expense in this case from the treatment afforded AIU in its last two rate cases, where pension and OPEB expense were established based on expense levels for the year following the test year, because the timing of the rate cases allowed for consideration of the final actuarial reports in those proceedings. Regardless of whether the actuarial reports were considered, AIU claims they were not part of the record in the prior proceedings.

AIU says Staff also seems concerned with calculating pension and OPEB expense based on data that does not match a calendar year. AIU asserts that it is unaware of any rule that requires pension and OPEB expense to be determined based on calendar year data. AIU asserts that normalization calculations and pro forma adjustments for various types of expenses are often determined based on periods that do not match a calendar year. AIU claims there is no reason to treat pension and OPEB expense any differently.

AIU suggests that the Commission does not have to accept at face value its representation that there will be no material difference between the July 2009 report and the final actuarial report. In testimony and in its Initial Brief, AIU offered to submit the final actuarial report for 2009, in order to confirm the accuracy of the July 2009 report. AIU says Staff rejects this idea, claiming it is unaware of any other proceeding where the record is purposefully held open for the entry of documentation supporting a pro forma adjustment until well after the hearings in the matter are concluded. AIU cites Docket No. 07-0566, where AIU says Staff entered a stipulation with ComEd requiring ComEd to file a post-hearing reconciliation of actual versus pro forma capital additions. AIU further suggests the Commission would be within its authority, under Section 200.875 of Part 200, to also accept post-hearing evidence confirming the accuracy of AIU‘s pension and OPEB expense.

b. Staff Position

Staff has proposed an adjustment limiting pension and OPEB costs to the December 2008 level, which Staff says is known and measurable. Staff indicates that AIU initially proposed to set pension and OPEB expense at the budgeted 2010 level; however, in Surrebuttal Testimony, AIU revised its proposal to set the test year expense to the level for the 12 months ending September 30, 2009.

Staff proposes to remove the pension and OPEB adjustment proposed by AIU since Staff believes the amounts proposed by AIU are not known and measurable. Staff states that the current 2010 pension budget is based on the updated actuarial report provided to AIU in July 2009. Staff indicates that AIU proposed updates to its initial position, which was based on a January 2009 actuarial report, in Supplemental Direct Testimony filed in July 2009. The fact that the budgeted amounts changed in the six months from January to July confirms Staff‘s position that the amounts do not meet the Commission‘s known and measurable standard. Staff argues that the 2010 benefits budget is based on a variety of assumptions, expectations, and trend analyses, none of which meet the Commission‘s known and measurable criteria.

According to Staff, the actual amounts recorded in AIU's books for pension expense at September 30, 2009 are not known and measurable because those estimated amounts are based on the reports prepared by Towers Perrin in January 2009 and July 2009. It is Staff's position that the actual pension cost for the year ending December 31, 2009 and the employer contribution for the plan year beginning January 1, 2009 will not be determined until the year end 2009 actuarial study has been completed, after the record in these proceedings will be marked heard and taken. In addition, Staff contends that the changes to AIU headcount as a result of the workforce reduction occurring in the fourth quarter of 2009 are not reflected in the amounts recorded on AIU's books as of September 30, 2009. Staff insists that AIU's alternate proposal to include pension costs through September 2009 does not reflect a known and measurable change and must be rejected.

Staff disputes AIU's suggestion that Staff acknowledges that the amounts provided on the July 2009 valuation report and the amounts recorded on the books of AIU at September 2009 are the “same amounts.” Staff asserts that the amounts recorded on the books at September 2009 are <u>based on</u> the amounts in the July 2009 report. Staff says since the July report represents a 12-month period and the amounts on the books at September 2009 are for a 9-month period, the amounts would not reasonably be the same.

Staff also disputes AIU's claim that no reason, rationale, or record evidence is cited to support the assumption that the amounts booked through September 30, 2009 could change. Staff states that during cross examination, Ms. Ebrey stated that the workforce reduction that occurred in November and December 2009 would, in her opinion, meet the definition of a significant event that would in turn impact the expense for 2009, yet would not be reflected in the September 30, 2009 balance per AIU books.

Staff says that during the evidentiary hearings, AIU attempted to gain Staff‘s agreement that the record in these proceedings could be held open until the final actuarial study for 2009 was prepared. Staff is unaware of any other proceeding where the record is purposely held open for the entry of documentation supporting a pro forma adjustment until well after the hearings on the matter have concluded. In Staff's view, such a tactic is clearly contrary to the known and measurable criteria which Section 287.40 requires to be “individually identified and supported in the direct testimony of the utility” when the case is filed, not after the evidentiary hearing.

Staff states that both it and AIU reflected reductions related to the production retiree expense that is included in the pension and OPEB balances. According to Staff, the theory behind the two proposals is the same. Staff says that it and AIU agree that the costs associated with production retiree pensions and OPEBs should be removed from the revenue requirement. According to Staff, the only difference is the timeframe for the costs that are removed. Staff contends that the decision on this issue is derivative of the Commission conclusion on the proper period for measurement of pension and OPEB costs.

c. IBEW Position

IBEW agrees with AIU that the 12 months of actual expense from October 2008 through September 2009 are the proper measure of pension, OPEB, and major medical expenses. IBEW claims such expenses are known and measurable, as the expenses have already been incurred and recorded by AIU. IBEW claims actuarial studies have not been required to establish actual pension and OPEB expenses in past rate cases, and even if such a report is required, it will soon be available.

d. Commission Conclusion

The Commission understands that everything else being equal, a decline in financial markets would cause an increase in pension and OPEB expense. Nevertheless, financial markets, by their very nature, fluctuate over time. Whether the declines in asset values experienced by AIU in 2008 have been fully recouped is unknown but, there is no question that these asset values are different than they were at December 31, 2008 as well as September 30, 2009. The Commission's point is that many things fluctuate after the end of the test year. Some changes benefit the utility, while others are detrimental to the utility. Presumably, AIU selected a historical test year of calendar year 2008 because this test year is beneficial to it.

In the Commission's view, Staff has raised valid concerns about whether AIU's proposed pro forma adjustment constitutes a known and measurable change. Among other concerns, the Commission notes that AIU's proposal to use the twelve months ending September 30, 2009 for measuring pension and OPEB expense was initially proposed as an alternative in AIU's Rebuttal Testimony and became its primary proposal in AIU's Surrebuttal Testimony. The Commission understands that parties' positions typically evolve throughout a contested rate case; however, Section 287.40 of Part 287 specifically requires that any proposed pro forma adjustments shall be individually identified and supported in the Direct Testimony of the utility. In this instance, the Commission finds AIU's proposed pro forma adjustment to pension and OPEB expense is not supported by the record and it is therefore rejected.

4. NESC Expenses

a. Staff Position

Staff expressed concern that AIU proposed to recover a greater amount than appropriate for correction of National Electrical Safety Code (―NESC”) violations. Staff indicates that AIU is required to repair or replace distribution facilities that are in violation of the NESC, and that the AIU‘s circuit inspection program appears to be an effective tool to identify locations that require NESC-related repairs. Staff reports that the Commission‘s Order in AIU‘s prior rate proceeding stated in relevant part, ". . . ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." (Docket Nos. 07-0585 et al (Cons.), Order at 142)

Staff asserts that ratepayers should not bear AIU‘s estimated test year repair costs for four specific NESC-related repair categories for which AIU proposes recovery: (1) missing guy guards, (2) down guys where no insulator exists in the guy wire, (3) overhead guys where no insulator exists in the guy wire, and (4) ungrounded metal underground risers. According to Staff, for all four of these repair categories the utility left off a required part when making the initial installation, so that the installation was in violation of the NESC. Staff claims that although the cost of installing the part would have been negligible at the time of the initial installation, AIU proposes to recover from ratepayers its estimated test year costs for installing the missing parts. Staff believes AIU‘s proposal is inconsistent with the Commission‘s Order in Docket Nos. 07-0585 et al (Cons.), and would cause the utilities to recover amounts far greater than what the utility‘s costs would have been, had the utility installed the part at the time of initial construction, as it should have done.

In support of AIU‘s proposal to recover its estimated test year costs for the four specific NESC-related repairs, AIU claims it did not re-do work previously performed by the utility when making the repair, so AIU did not categorize those repairs as ―re-work” to be excluded from cost recovery. AIU uses the example of guy guards to illustrate AIU‘s method of categorizing work as either ―re-work” or ―new work,” explaining that if a guy wire does not have the required guy guard, then ratepayers would not have paid for the guy guard in the first place, so that installing the guy guard would be ―new work,” and should be eligible for cost recovery. AIU asserts that no locations with missing guy guards should be considered NESC-related re-work, and ratepayers should bear all test year costs related to installing them. Likewise, AIU reasons that ratepayers had not previously paid for missing down guy insulators, missing overhead guy insulators, and missing grounds on metal underground risers.

Staff suggests that the very fact AIU was not aware that the required parts were missing casts doubt on its knowledge of whether or not ratepayers previously paid for the missing part. Regardless of whether or not ratepayers previously paid for the installation of the missing parts, in every case, Staff maintains that utility costs for installing the missing part at the time of initial construction would have been negligible. AIU does not know its actual test year costs to install these missing parts, stating it would be difficult, if not impossible, to determine a precise breakdown of labor costs for NESC and non-NESC repairs. Staff believes recovery of estimated test year cost for installing NESC-required missing parts would be unfair to ratepayers who may have already paid for them.

Because AIU claims not to know its actual test year costs for its NESC-related repair work, Staff understands that AIU estimated its test year costs for each NESC-related repair activity by averaging the costs of jobs with work descriptions that appeared to closely match each NESC-related repair category. In Direct Testimony, AIU estimates that the amount of its expenditures for NESC-related repairs that should be eligible for recovery is $4,500,000, and the amount of its expenditures for NESC-related repairs that should be excluded from recovery is $8,600,000.

AIU asserts that installing a missing guy guard, insulator, or ground merely completes the construction of the infrastructure in compliance with the NESC. AIU uses an example of installing smoke detectors in two homes, one with smoke detectors installed incorrectly, and one with no smoke detectors installed at all, in order to illustrate AIU's position on cost recovery for NESC-related repairs. AIU states that in one home there is time and cost required to correct the improperly installed smoke detectors, and in the other there was never an initial amount of time and cost spent installing the detectors.

Staff does not find AIU's rationalization for charging ratepayers the utility's estimated test year cost to install missing parts to be reasonable, and believes that the requirements for the missing parts have existed for several decades in Illinois, so that the utility should have known of the requirement at the time of initial construction, and initially completed the installation correctly. Staff says AIU agrees that the missing parts should have been installed at the time of initial construction. In Staff's view, AIU's smoke detector analogy does not accurately describe the situation associated with AIU's NESC-related repairs. The situation, Staff contends, is not that AIU did not install down guys, overhead guys, or metal underground risers; instead, the situation is that AIU (or the predecessor company) left required parts off of these facilities when it installed them. Staff claims this is more similar to installing a smoke detector but leaving the sensor or battery out of it.

Staff states that the repair costs associated with individual locations for each of the four NESC-related repair activities identified are not large, but the large number of locations where AIU performed each repair activity during the test year causes the aggregate costs to warrant the Commission's careful consideration. In every case, Staff says the cost for the utility to install the missing part when the facility was initially constructed and that the NESC required would have been negligible, but AIU's test year costs are not negligible. Staff indicates that AIU seeks to charge ratepayers $235.52 per repair location to install insulators in down guys at more than 5,200 locations, even though AIU's average material cost for the insulators has been approximately $16, and its incremental labor cost to install the insulator would have been negligible at the time of initial construction. Staff indicates that AIU proposes to charge ratepayers $125 per installation for installing 6,399 guy guards during the test year, even though each guy guard costs slightly more than $2, and would have added no additional labor costs to the initial installation. Staff witness Rockrohr explains why actual installation costs would have been negligible. (See Staff Ex. 24.0R at 9-10)

Staff says that in its Surrebuttal Testimony, AIU suggests that even if the Commission were to accept Staff's position regarding NESC-related repairs, the proposed disallowance for guy guards should be modified. AIU believes 90% of the 6,399 missing guy guards that AIU installed during the test year had been removed after the AIU installed them. Staff's opinion has not changed with regard to guy guards. Staff continues to believe that the percentage of guy guards removed after they are initially installed is very small, and asserts that no more than 10% of the 6,399 guy guards that AIU installed during the test year were replacements for guy guards that had been previously installed and removed.

AIU further recommends that, should the Commission choose to allow AIU to recover only material costs for the guy guards, insulators, and grounds, then test year costs should be used, rather than average material costs. According to Staff, however, AIU could not demonstrate whether or not ratepayers have already paid for the missing parts at locations with NESC violations, and does not recommend that the Commission allow cost recovery for these materials. Should the Commission choose to allow recovery of the utility‘s material costs associated with these NESC-related repairs, Staff proposes the use of the average material cost listed in Staff Ex. 24.0 (Rev.) Attachment E, which Staff believes more accurately reflects the material costs at the time that the material should have been installed.

Finally, with regard to AIU‘s obligation to correct NESC violations that it discovers, Staff wishes to make the Commission aware of AIU‘s lengthening timelines. Staff states that in its NESC Corrective Action Plan, dated October 31, 2007, AIU agreed to identify and correct all existing NESC violations on the three electric utilities‘ distribution circuits by the end of 2011. After it made its rate case filing, AIU notified Staff that it was extending the time to correct its existing NESC violations until the end of 2013. Staff reports that in its Surrebuttal Testimony, AIU indicates that it might extend its NESC violation correction timelines still further.

Staff insists that AIU should correct its NESC violations as quickly as it can by using a systematic and thorough inspection process. Staff is concerned that after already extending its previously agreed upon timelines in July of 2009, in its surrebuttal testimony, AIU threatened to delay completion of its corrections of NESC violations still further if the Commission does not grant the cost recovery it seeks. Staff finds this veiled extortion by AIU to be troubling. Staff argues that AIU is already in violation of NESC and Commission rules as a result of its own construction practices at the time of initial construction, and AIU admitted that it should have known the missing parts were required at the time of initial construction. Staff urges the Commission to order AIU to complete its corrective actions for existing NESC violations by no later than the end of 2013.

According to Staff, IBEW‘s concern appears to be that reduced recovery for NESC-related repairs could lead to AIU reducing expenditures for other maintenance projects, which could have a negative impact on service reliability, and could result in a loss of jobs. Staff is unsure whether or not IBEW‘s concern is valid. Though Staff does not believe it would be a good idea to do so, Staff says AIU could decide to reduce its maintenance expenditures for any number of reasons, independent of the Commission‘s decision regarding this NESC issue. While potential job loss might be a legitimate concern, Staff does not believe the Commission should base its decision upon this concern.

b. AIU Position

AIU seeks recovery of a portion of its NESC-related repair costs, specifically, the costs for “new work” repairs to bring facilities into compliance with NESC without rebuilding existing infrastructure or duplicating work previously performed. With respect to these NESC-related “new work” repairs, Staff contends that ratepayers should not pay now to install parts that should have been installed when the infrastructure was initially constructed. AIU claims it is not seeking to recover the costs of fixing incorrectly installed or constructed infrastructure. Rather, AIU seeks recovery of the costs of installing infrastructure components that were missing entirely. AIU contends that adding on missing parts to existing infrastructure does not charge ratepayers a second time to correct improperly constructed facilities. AIU believes it is fair and reasonable for AIU to recover NESC-related “new work” costs from ratepayers in instances where the repairs do not require AIU to reconstruct existing infrastructure or redo work previously done improperly.

AIU argues that recovery of NESC-related expenditures does not turn on whether those expenditures were necessary and prudent. AIU says no party to this proceeding has suggested that the NESC-related repairs at issue should not have been performed or were not performed at a reasonable cost. AIU claims it has pursued vigorously the enhancement of its acquired electric infrastructure to correct problems that existed prior to its ownership and to ensure safe and reliable distribution systems since its ownership. Specifically, AIU says it has implemented a system-wide circuit inspection program to, among other things, find and resolve NESC-related violations on its circuits. AIU indicates it has submitted to Staff an NESC Corrective Action Plan that sets forth a commitment and timeframe for inspecting all of its Illinois distribution circuits and correcting all existing NESC violations.

AIU understands Staff to be interpreting the Commission's conclusion in its last rate proceeding Order to mean that if ratepayers already paid the utility for the installation, AIU should not charge ratepayers a second time to properly install the infrastructure. In AIU's view, Staff‘s position fails because AIU is not asking ratepayers to pay twice to construct distribution infrastructure in compliance with the NESC. In the 2008 test year, AIU says it performed over 52,000 reliability and corrective repairs on its circuits. AIU indicates that out of the 25 types of repairs performed, AIU identified 11 categories of repairs that concerned NESC issues. AIU claims it spent a total of approximately $13.1 million for these 11 categories of NESC-related repairs. AIU says it does not seek recovery of all, or even a majority, of these repair costs. Cognizant of the Commission‘s concern that ratepayers not pay twice to properly construct infrastructure in compliance with the NESC, AIU says it is not seeking to recover “re-work” costs. For example, AIU indicates it does not ask for recovery of costs to correct improperly placed insulators on guy wires. Similarly, AIU indicates it does not seek recovery of costs to correct inadequate line clearance where lines were installed too close to the ground, another wire, or structure. AIU does not seek recovery of costs to replace low brackets on underground risers. Of the $13.1 million in NESC-related repair costs, AIU claims it excluded approximately $8.7 million spent on —re-work” repairs from its request for cost recovery in this proceeding.

Having excluded —re-work” repair costs, AIU indicates that the —new work” costs for which it seeks recovery in this proceeding total approximately $4.4 million. Staff, however, contends that a large portion of AIU‘s NESC-related —new work” costs are really —re-work” costs that should be disallowed. Staff recommends that 90% of AIU‘s test year costs to place guy guards on existing guy wires, 100% of its costs to install insulators on existing guy wires, and 100% of its costs to ground existing underground risers be considered —re-work.”

AIU argues that the installation of missing guy guards, insulators, and grounds does not require AIU to reconstruct improperly constructed infrastructure. AIU contends that unlike the —re-work” repairs necessary to correct inadequate wire clearance, remove low brackets from risers or replace improperly placed insulators, the installation repair work simply requires AIU to add missing parts to existing infrastructure. The cost of installation, AIU asserts, is essentially the cost required to complete construction of the infrastructure in compliance with the NESC. Because the parts were never installed and the work was never performed, AIU claims ratepayers were never charged for the costs associated with the installation. AIU believes that approving recovery of such NESC-related —new work” installation costs is consistent with the Commission‘s Order in AIU‘s prior rate case because ratepayers are not being charged a second time.

Staff also argues that the costs to install the parts at the time the infrastructure was initially constructed would have been negligible in comparison to the test year costs. AIU claims the added cost to install these missing parts, however, whether incurred during the test year or at the time of initial construction of infrastructure, is identifiable, quantifiable and material. In preparing its case, AIU says it calculated a reasonable average cost for each —new work” and —re-work” repair, relying on specific project data from actual work orders and job requests from the 2008 test year. In preparing its rebuttal case, AIU says it relied on the same cost data and actual field experience to derive a reasonable average labor cost for a specific step in the process of installing insulators in existing guy wires that could be considered —re-work.” AIU also indicates it explained the basis and methodology for its cost calculations and also calculated the average man-hours to install these parts. AIU contends that this analysis demonstrates that the installation of these parts at the initial time of construction would have resulted in additional billed time for labor. Because the work was not performed, AIU asserts that ratepayers did not pay this additional labor cost. In addition, AIU claims the parts themselves would have remained in inventory for future use. AIU says ratepayers would not have paid for these parts until they were used.

AIU claims that Staff has not presented sufficient analysis or data to demonstrate that the labor cost to install these missing parts at the time of initial construction would have been negligible. According to AIU, Staff has not demonstrated that the ratepayers would have somehow previously paid for materials never before used. AIU says its test year costs, which again were calculated using cost data for the individual repairs are not negligible. If AIU is incurring incremental costs during the test year to install these missing parts, AIU wonders how it could not have incurred incremental costs if the parts had been installed at the time of initial construction. AIU argues that the only basis for Staff‗s opinions that these costs would have been negligible or non-existent is speculation.

Finally, AIU says it is not attempting to extort the Commission, as Staff alleges. AIU states that it is committed to inspecting and correcting all existing NESC violations as quickly as possible, but that it takes money do so. AIU claims it is asking to not be placed in the untenable position of having to perform this work without the necessary funds. AIU asserts that it recognizes that the Commission has held that much of the funding necessary for this work should be borne by shareholders. AIU believes its proposal to recover only $4.4 million in costs for NESC-related ―new work" repairs fairly and reasonably allocates to ratepayers only those costs for labor and materials previously not paid.

c. IBEW Position

IBEW says AIU should be allowed to recover its expenses for ―new work" performed to comply with the NESC. IBEW states that AIU is not seeking to recover the costs of fixing incorrectly installed or constructed infrastructure, but rather the costs of installing infrastructure components which are missing entirely. According to IBEW, the man-hours expended on components installed are the same as those required to complete the work in the first instance, but ratepayers have not yet paid for the repairs. IBEW claims there is minimal expense for crews to return to sites to conduct the ―new work," because it was scheduled to coincide with other necessary repairs at the same site.

IBEW also claims an inadequate recovery would impact both customer service and the Illinois workforce. If not allowed to recover the costs of NESC related expenses, IBEW states that AIU may need to reduce expenditures on other maintenance projects, including reductions in the staff and contractors responsible for such maintenance. IBEW suggests this could have a negative impact on service reliability due to less preventative maintenance. In addition, IBEW says a reduction in repair staff and contractors would be a loss of jobs at a time when the Illinois workforce is already challenged.

d. AG/CUB Position

In its Reply Brief, AG/CUB voices support for Staff's proposed adjustment. In AG/CUB's view, ratepayers should not be liable for work that was done improperly or not done at all in violation of the NESC, regardless of the entity owning the utility at the time.

e. Commission Conclusion

AIU proposes to include in operating expenses certain costs associated with installing NESC required facilities that it considers to be new work. Staff objects to recovery of four specific types of costs (1) replacing missing guy guards, (2) correcting down guys where no insulator exists in the guy wire, (3) correcting overhead guys where no insulator exists in the guy wire, and (4) installing grounds on ungrounded metal underground risers. Staff argues that the incremental labor costs to install these facilities would have been negligible if the work had been done correctly at the time of initial construction. AIU claims the incremental labor is the same regardless of when the facilities are installed.

In discussing alternatives to its primary position, AIU asserts that 90% of the missing guy guards installed during the test year were replacements after the original guy guard had been installed. In contrast, Staff argues that no more than 10% of the missing guy guards installed during the test year were replacements after the original guy guard had been installed. AIU also recommends, if the Commission decides to allow AIU to recover only material costs, test year costs rather than average material costs should be utilized. In contrast, while Staff does not believe material costs should be recovered from ratepayers, Staff recommends the use of average material costs rather than test year costs, should the Commission decide to allow recovery.

The Commission's review of the record suggests that AIU has overstated the cost of installing the facilities in question. For example, the Commission can not believe that the average incremental cost of installing a $2.19 guy guard, at the time the guy is installed is over $120. This calls into question all of AIU's estimates of installation cost. The Commission believes that Staff witness Rockrohr's position that the cost of installing the four facilities at issue here would have been negligible is much closer to the truth. Similarly, the Commission is convinced that Mr. Rockrohr's estimate of the percentage of guy guards that were replacements after an original guy guard had been installed is superior to AIU's estimate.

The Commission believes that it is reasonable for AIU to be allowed to recover from its customers the average cost of materials associated with the four facilities at issue here. The Commission also believes that AIU's suggestion that test year material costs should be used would overstate what ratepayers would have been charged if the projects had been completed correctly at the time of the original construction. As a result, the Commission finds Staff's material costs to be superior to AIU's. The Commission concludes that for NESC work, AmerenCILCO should be allowed to reflect in revenue requirement an amount of $13,097, AmerenCIPS should be allowed to include in revenue requirement an amount of $28,791, and AmerenIP should be allowed to include in revenue requirement an amount of $57,730. The values are shown on Staff Ex. 24.0R, Attachment E.

Finally, the Commission is greatly concerned about AIU's commitment to providing safe, reliable electric service. According to Staff, in its NESC Corrective

Action Plan, AIU agreed to identify and correct all existing NESC violations on the utilities' distribution circuits by the end of 2011. Thereafter, AIU notified Staff that it was extending the time to correct its existing NESC violations until the end of 2013. Staff reports that in its Surrebuttal Testimony, AIU indicates that it might extend its NESC violation correction timelines still further. AIU's disregard for this Commission's remonstrations regarding correction of safety violations that resulted from AIU's failure to follow NESC codes is, simply put, of significant concern to this Commission. Combined with AIU's request to recover these costs after our decision on this matter in Docket Nos. 07-0585 et al (Cons.), where we stated clearly that, "ratepayers will not be responsible for paying the costs associated with correcting distribution facilities that were initially constructed in a manner that does not comply with the NESC." (Docket Nos. 07-0585 et al (Cons.), Order at 142), raise significant concerns about AIU's management of this issue. In addition, AIU's threat that it might reduce tree trimming activities in the event its proposed expenditure recoveries are not approved, raises significant reservations that AIU may not be providing safe and reliable service. The record indicates that AIU is expending resources on activities such as economic development and the promotion of renewable electric generation. While the Commission does not necessarily want to discourage such activities, AIU needs to reevaluate its priorities. The Commission requires that AIU make the activities that are essential to the provision of safe, reliable utility service the highest priority in serving their customers.

As for Staff's recommendation that the Commission order AIU to complete its corrective actions for existing NESC violations by no later than the end of 2013, the Commission believes it is necessary to require AIU to complete all work by the end of 2013. The Commission is aware of the severity of NESC violations and requires AIU to correct these violations by the end of calendar year 2013, at the latest, in order to comply with this Order. Any further AIU requests for deviation from this schedule may only be granted by formally petitioning the Commission.

5. Amortization of IP Merger Expense

a. AIU Position

AIU indicates that in Docket No. 04-0294, the Commission approved a reorganization that resulted in the merger of IP with Ameren, creating the entity now known as AmerenIP. As part of this reorganization, AIU states that the Commission authorized AmerenIP to record up to $67 million of merger-related costs as a regulatory asset to be amortized between 2007 and 2010. AIU says AmerenIP will not fully recover the authorized $67 million by December 2010. According to AIU, test year amortization is $16.75 million, which AIU says represents the balance of the authorized $67 million regulatory asset not yet recovered.

AIU reports that Staff, AG/CUB, and IIEC object to including the full test year amortization in rates. Staff argues that any recovery after 2010 is prohibited by the Order in Docket No. 04-0294. AG/CUB and IIEC argue that because the remaining amortization will be $11.167 million when new rates go into effect in May 2010, AmerenIP will over recover the regulatory asset if new rates are in effect for more than one year. AIU indicates that Staff and IIEC propose to amortize the balance of the regulatory asset over two years, while AG/CUB proposes a three year amortization.

To reduce the number of contested issues, AIU indicates it agrees with the Staff and IIEC approach of amortizing the remaining balance of the regulatory asset, calculated as of May 2010, over two years. AIU says this adjustment is reflected in AmerenIP's statement of operating income. If the Commission adopts this proposal, AIU requests that the Commission make an express finding that AIU will be permitted to adjust its regulatory asset amortization at May 1, 2010, as recorded in the books of AmerenIP, to match the same two year period established for rates.

AIU states that AG/CUB agrees in principle with the adjustment but maintains its preference for a three-year amortization period. AIU says AG/CUB does not explain why a three-year amortization period is more appropriate than the two year amortization that everyone else agrees to. AIU believes AG/CUB's alternative amortization period should be rejected.

b. AG/CUB Position

In the present case, AmerenIP is proposing to recognize annual amortization expense of $16,750,000 per year, with $11,849,000 included in pro forma electric expenses and $4,901,000 included in pro forma gas expenses. AG/CUB asserts that as of May 2010, when the rates established in this case will go into effect, the costs remaining to be recovered will be only $11,167,000. With annual amortization of $16,750,000, AG/CUB claims these $11.1 million in costs will be fully recovered less than one year after the rates in this case go into effect. According to AG/CUB, if the rates are in effect for more than one year, as it is reasonable to assume, then the rates being charged by AmerenIP after that time will continue to recover an amortization expense that no longer exists.

To avoid over-recovery of the AmerenIP regulatory asset, AG/CUB believes the remaining balance as of May 2010 should be amortized over the expected period that the rates in this case will be in effect, and the pro forma amortization expense should be adjusted accordingly. AG/CUB states that amortization of this balance over three years results in annual amortization of $3,722,000, or $2,633,000 for AmerenIP electric operations and $1,089,000 for AmerenIP gas operations. AG/CUB indicates that these amounts are less by $9,216,000 and $3,812,000, respectively, than the amortization expenses included in pro forma expenses by AmerenIP.

c. Staff Position

Staff urges the Commission to accept its proposed adjustment to the amortization of the AmerenIP regulatory asset which limits the recovery to the amount allowed by the Commission in Docket No. 04-0294. Staff believes that the evidence supports Staff's adjustment which spreads the remaining 8-months amount to be recovered over the two year amortization period consistent with the proposed period for rate case expense. Staff does not take issue with AIU adjusting its regulatory asset amortization, as recorded on the books of AmerenIP, to match the amount and two-year period proposed by Staff's adjustment.

d. IIEC Position

IIEC recommends amortizing over two years the level of merger expense which will still need to be collected when new rates take effect in this case. For purposes of this adjustment, IIEC assumed that rates in this case will become effective May 1, 2010. IIEC says this would mean that eight months of the annual amortization expense will still need to be collected in rates. IIEC is proposing that the eight-month total of unamortized expenses of $11.2 million be amortized over the subsequent two years. IIEC asserts that this two year period is roughly consistent with the interval between AIU's last rate case and this one, and is consistent with AIU's proposed period for amortizing rate case expense in this proceeding.

If IIEC's adjustment to the merger expense amortization is accepted and AmerenIP does not file for another rate increase within two years, at the end of the two year period, IIEC says it will begin to over-collect only $5.6 million of fully amortized merger-related expense on an annual basis. IIEC asserts that this $5.6 million dollar recovery must be compared to the $16,750,000, which AmerenIP would otherwise over-collect on an annual basis beginning January 1, 2011 in the absence of IIEC's adjustment.

In the alternative, if the Commission does not want to change the current amortization expense for the AmerenIP merger costs, then IIEC urges the Commission to limit many, if not all, of the requests by AmerenIP to update its case through pro forma adjustments through May 2010. Specifically, IIEC believes the Commission should limit the increase in AmerenIP's cost of service through May 2010 to only recognize those costs which are in excess of the over-collections above.

e. Commission Conclusion

AIU, Staff, and IIEC all agree that AIU should be authorized to amortize the remaining balance of the regulatory asset, calculated as of May 2010, over two years. AG/CUB recommends amortizing the remaining balance over three years. The Commission believes that an amortization period of two years is appropriate with regard to the regulatory asset at issue here. This period is consistent with the period over which AIU proposes to amortize rate case expense and is consistent with the time period between AIU's last rate case and this proceeding. AG/CUB's proposed three year amortization period has not been adequately supported and it is therefore rejected. The Commission adopts a two year amortization period for the regulatory asset and AIU is hereby permitted to adjust its regulatory asset amortization at May 1, 2010, as recorded on the books of AmerenIP, to match the two year period established for rates.

6. Economic Development Expenses

a. AIU Position

AIU seeks to recover approximately $600,000 of labor and labor-related expenses incurred by the Ameren Economic Development Department ("ED Department") (and accounted for in Account 912) in AIU's approved operating expenses. AIU states that the ED Department, as part of AMS, provides economic development services to AIU to assist Illinois service area communities in attracting new business and investment, which supports the economic viability and sustainability of service area community economies in terms of population growth and maintenance, housing, new investment, and improved tax base. For AIU customers' communities, AIU says the ED Department provides technical services and programs to help enhance the local/regional economic development capacity, support community planning, and successfully prepare those communities to compete for new business investment and retention. For business development, AIU says the ED Department partners with local/regional/state governmental and non-governmental development organizations to attract new business growth and investment by engaging in business outreach activities regarding business location assistance services available via AIU. According to AIU, the ED Department is also the point-of-contact for new and expanding business inquiries and offers Illinois communities programs to support canvassing of business for retention and expansion opportunities to utilize existing infrastructure.

AIU contends that the services provided by the ED Department benefit AIU's ratepayers across all customer classifications in the communities and businesses with whom it works. AIU asserts that its business and community development services provide economies of scale to programs and activities that would otherwise not materialize. According to AIU, the ED Department's efforts to add new customers to AIU's existing delivery infrastructure system have the added benefit of spreading fixed operating costs across a broader customer base, which AIU says ultimately benefits all ratepayers. In addition, AIU indicates that the ED Department works with AIU's customers and customers' communities to avoid plant closure, job loss, and community disinvestment. AIU says the ED Department also supports existing customers to ensure continued and efficient use of existing delivery infrastructure and works to avoid any disruption to existing service when connecting new industrial or commercial customers.

As an example of the tangible results of the ED Department's efforts, AIU states that in 2008, the ED Department helped support the location/expansion of new business, which AIU says resulted in the projected creation of 546 direct new jobs throughout its Illinois service territory, an additional 855 projected new indirect jobs resulting from project multiplier effects, and approximately $222 million in new project investment in Illinois. With each location/expansion, AIU says the ED Department coordinated development activities on behalf of AIU until the electric meter was properly installed and the prospect was a customer of record for AIU. According to AIU, no party has disputed either the essential services provided by the ED Department during these projects or the tangible benefits enjoyed by AIU's customers as a result.

AIU believes that Staff's reliance on Section 9-225 of the Act is misplaced. AIU argues that even if Section 9-225 applied to this issue, AIU has established that its economic development labor and labor-related expenses benefit customers and are incurred in the best interest of those customers. According to AIU, Section 9-225 only restricts recovery, in certain circumstances, of —Advertising" expenses. AIU states that —Advertising" is explicitly defined as —the commercial use, by an electric, gas, water, or sewer utility, of any media, including newspapers, printed matter, radio and television, in order to transmit a message to a substantial number of members of the public or to such utility's consumers." AIU contends that, —Advertising," as defined by the statute, is not the sort of expense for which it seeks recovery. AIU claims it has taken a conservative approach by including only labor and labor-related costs for the ED Department in the adjustment to Account 912 and that no other charges have been included.

Even if the Commission were inclined to apply Section 9-225, AIU argues that its economic development labor and labor-related expenses would still be recoverable. AIU says that pursuant to Section 9-225(b), recovery of —promotional, institutional, or goodwill" advertising expenses is appropriate if —the Commission finds the advertising to be in the best interest of the Consumer." AIU states that while it believes that labor and labor-related expenses are not —advertising," even if they were so considered, the evidence establishes that the ED Department provides services that ultimately benefit AIU's customers. AIU claims Staff has presented no evidence to the contrary, and acknowledged that AIU's customers could enjoy significant benefits from the types of results obtained through the labor of the ED Department.

AIU complains that Staff focuses solely on whether AIU's investors also benefit from the ED Department's work. AIU contends that the issue of AIU's investor benefits is a red herring. AIU says that Section 9-225(b) contains no mention of investors' interest. According to AIU, the only consideration is whether the advertising expenses incurred were —in the best interest" of AIU's customers. AIU says the best interests of customers and shareholders are not mutually exclusive. AIU adds that allowing recovery would be consistent with prior decisions of the Commission. (AIU RB at 72, citing Docket No. 91-0147 (1992), Order at 174-77 (allowing recovery of economic expense because —it benefits ratepayers and promotes more efficient use of its system"))

AIU states that as a secondary argument, Staff asserts that AIU's expenses should be removed because they are —not necessary" to —providing utility service." AIU claims Staff's position is inconsistent with the law and the record evidence. According to AIU, various sections of the Act contradict the premise of Staff's argument. AIU claims that many provisions allow recovery of expenses associated with activities that are not strictly necessary to provide utility service. For example, the Act permits recovery of —Advertising" expenses under Section 9-225 when doing so is in the best interest of customers. AIU also states that utilities can provide service without making charitable donations. Section 9-227 of the Act provides that the Commission ―is prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes." AIU contends that if the Commission can not *per se* preclude recovery for donations that benefit the public welfare, Staff's position that the Commission must *per se* preclude recovery for labor and labor-related expenses that benefit the public welfare can not be correct. AIU insists that its economic development labor and labor-related expenses, while not necessarily required to ―keep the lights on" are not *per se* unrecoverable.

b. Staff Position

Staff proposes adjustments to remove ED Department labor and labor-related costs from AIU's revenue requirement, as presented in Staff Ex. 18.0R, Schedule 18.06. According to Staff, Section 9-225 of the Act prohibits recovery of costs of a promotional, institutional, or goodwill nature. Staff believes that these ED Department expenses are unrecoverable under the Act.

Staff relates that its recommendation disallowing ED Department labor and labor-related costs was not initially made in its Direct Testimony. Initially, Staff proposed an adjustment to remove Demonstrating and Selling Expenses, Account 912, from each gas utility's respective revenue requirement because the transactions identified in that account were not recoverable. Staff says a similar adjustment to the AIU electric utilities was not necessary, as AIU did not claim any Account 912 costs for the electric utilities. Staff states that in Rebuttal Testimony, however, AIU offered alternative adjustments which purported to include in Account 912 only what AIU termed as ―economic development labor and labor-related costs" for both the AIU electric and gas utilities.

In Rebuttal Testimony, Staff proposed an adjustment to remove the newly-defined ED Department expenses as presented in the AIU Rebuttal Testimony. Review of AIU Rebuttal Testimony and data request responses led Staff to conclude that economic development labor and labor-related costs as presented by AIU are for promotional, institutional, and goodwill purposes, which, while perhaps promoting good corporate citizenship, keeping AIU in contact with other members of the business community, and recruiting new corporate customers, are not necessary in providing utility service. Staff insists that such costs should be the responsibility of the investors, not the ratepayers. In Surrebuttal Testimony, AIU expressed its disagreement with Staff, further explaining the services provided by the ED Department.

According to Staff, there is no disagreement regarding the nature of the services provided to AIU by the ED Department. Staff indicates the disagreement relates to who should shoulder the burden of the expenses related to these services. Staff maintains that AIU shareholders should bear this burden, as the costs are non-recoverable per Section 9-225 of the Act, and benefit AIU and shareholders by increasing revenues.

In effort to justify the recoverability of ED Department costs, Staff says AIU stated in its Surrebuttal Testimony that the services benefit ratepayers by providing information to prospective new businesses, by attracting new investment to areas that have existing AIU infrastructure, by spreading fixed operating costs across a broader customer base, and by ensuring continued use of existing infrastructure. Staff counters that such ED Department services benefit shareholders as well. AIU also avers that the services provided by the ED Department are an integral component in the process of providing utility service. Staff claims that AIU would provide utility service in the absence of such programs. Staff insists that ED Department costs are not necessary in providing utility service, and such costs should be the responsibility of the investors, not the ratepayers.

AIU claims that no party has disputed either the essential services provided by the ED Department during these projects or the tangible benefits enjoyed by the AIU customers as a result. Staff finds this statement misleading. While no party has disputed the services provided or the benefits AIU claims customers enjoy, Staff specifically states in its Rebuttal Testimony that the ED Department costs are not necessary in providing utility services. Staff‘s position is that ED Department services are not essential. Staff says AIU would provide utility service in the absence of such programs.

Staff disputes AIU's assertion that Staff agrees that the ED Department provides an essential function by answering questions from customers about the provision of utility service, including questions regarding expanding service or consuming service more efficiently. Instead, Staff believes that it sounds reasonable that a utility would be fulfilling an essential service by answering customers‘ questions and concerns regarding provision of service. Staff also takes issue with AIU's assertion that it agrees that AIU‘s customers benefit from efforts to actively increase its customer base because doing so spreads the fixed operating costs of AIU across a larger number of customers. Staff emphasizes that the addition of new customers between rate cases would have the effect of increasing company revenues, while costs included in rates would remain the same. Staff says that customer count and revenues would increase, but the costs and number of customers those costs are spread across would remain unchanged until the next rate case. At the time of the next rate case, Staff asserts that fixed costs to be spread across the new, increased number of customers would also increase due to the costs of new plant or increased O&M costs incurred to serve the new customers.

c. IBEW Position

IBEW believes that AIU‘s expenditures on economic development are beneficial not only to existing ratepayers, but also for the general Illinois economy and workforce as a whole, and should be recoverable. In addition to the general benefits due to increased economic development in its areas, IBEW alleges that existing ratepayers benefit when new customers are added to AIU‘s existing infrastructure.

d. Commission Conclusion

AIU proposes to pass along to customers approximately $600,000 of labor and labor related expenses associated with economic development activity. IBEW supports AIU's proposal. Staff opposes recovery of the costs from ratepayers arguing, among other things, that the economic development activity primarily benefits shareholders.

Staff asserts that the provisions of Section 9-225 of the Act prohibit AIU from passing the disputed costs along to ratepayers. AIU claims that economic development activity does not constitute advertising and that even if it did, because it provides benefits to ratepayers, such activity fits one of the exceptions in Section 9-225 and the costs can be passed on to ratepayers. In the Commission's view, the economic development activities fall under the definition of "promotional advertising" contained in Section 9-225 of the Act.

The Commission believes there is evidence that the economic development activities at issue provide, or at least potentially provide, benefits to both customers and shareholders. Contrary to AIU's suggestion, however, advertising that provides some benefit to customers is not necessarily in the customers' best interest. The economic development activities at issue here appear to provide significantly more benefits to AIU shareholders than to its customers. The fact that customers receive a tangential benefit from activities that primarily benefit shareholders does not mean the activities are in the best interest of the ratepayers or that any portion of the cost of such activities should be passed along to ratepayers. The Commission concludes that the economic development activities at issue here should not be included in the revenue requirement and Staff's proposed adjustment to remove such costs is hereby approved.

7. Workforce Reduction

a. Staff Position

Staff states that its revised proposed adjustment for the AIU workforce reduction reflected in the Appendices attached to its Initial Brief corrects payroll tax costs consistent with payroll taxes associated with other pay related adjustments. According to Staff this proposed adjustment does not reflect an offset for the one-time costs associated with severance pay to those employees taking the voluntary separation package.

Staff indicates that in Surrebuttal Testimony, AIU discussed certain disputes it has with Staff's proposed rebuttal adjustments. Accordingly, in its Initial Brief Staff revised its rebuttal position adjustment so that the incentive compensation costs already removed from the operating expenses are not double counted. In addition, Staff indicates it also reflected the jurisdictional allocations included in Ameren Ex. 51.9, for its electric utilities in the revised adjustment schedules.

Staff says AIU calculated the amounts for payroll taxes associated with the workforce reduction based on factors calculated by dividing payroll taxes into labor. Staff states that the resulting factors range from 4.19% - 5.25% for total payroll taxes, all of which Staff claims is less than the amounts for FICA tax alone. Staff asserts that during cross examination, AIU agreed that the tax rates for each of the three utilities would include 7.65% for FICA tax, 0.8% for Federal Unemployment Tax Act tax, 0.6% for State Unemployment Tax Act tax, and further that these tax rates would not vary between the utilities. Staff also claims AIU acknowledged that the complicated calculation it uses for the payroll taxes associated with the workforce reduction does not accurately reflect the correct adjustment and would require correction should the Commission approve AIU's proposed adjustment.

Staff asserts that its proposed adjustment for payroll taxes reflects the same calculation used for other payroll tax related adjustments, multiplying the amount of the compensation-related adjustment by 7.65%. Staff says that while AIU argues that the costs for severance pay should be recovered over a three-year period similar to rate case expenses, it also agrees with Staff that those costs are one-time costs.

AIU cites Docket No. 05-0597 as precedent for the approval of severance costs associated with the workforce reduction which took place in November and December 2009. Staff says the severance costs in that case were related to a specific Cost Savings Program called the Exelon Way program. According to Staff, the specifics of that program were provided under Section 285.3215, which provides a utility an incentive to initiate cost savings programs and outlines the specific detail required for recovery. Staff contends that no similar information was provided by AIU in the current cases. Staff states that AIU specifically excluded this information from its filing. Staff claims that only in response to discovery generated by a press release by AIU in early September 2009 did AIU provide to Staff the information about the workforce reduction. Staff says no detail of savings was provided until late October. Since the circumstances surrounding Docket No. 05-0597 are so different from AIU's cases, Staff insists that the conclusion in that case is not instructive for this case. Staff maintains that severance costs related to the AIU workforce reduction should not be allowed for recovery.

b. AIU Position

AIU agrees that an adjustment to labor and associated expenses (such as payroll taxes) is warranted to reflect decreased salary and benefits expense that will occur as a result of the buyout. AIU claims that Staff, however, has miscalculated the appropriate adjustment. AIU recommends that the Commission adopt the workforce reduction adjustment reflected in Ameren Ex. 51.9.

AIU asserts that the most serious flaw in Staff's proposed workforce reduction is Staff's failure to recognize that the long-term savings that will result from the workforce reduction come at a short-term cost. AIU says these costs total just over $2.7 million and consist mainly of employee severance payments. AIU indicates that Staff considers severance costs a one-time cost which does not reflect a normal on-going level of cost, and on that basis proposes to disallow severance costs in their entirety. AIU argues that the one-sidedness of this approach is obvious, for it provides ratepayers the full benefit of the cost-savings associated with workforce reductions while saddling AIU's shareholders with all of the costs necessary to achieve those benefits.

Rather than disallow severance costs in their entirety, as Staff proposes, AIU believes a more rational, and fairer, approach is to amortize these costs over a period of three years. AIU claims no party has argued that the severance costs incurred by AIU were unreasonable or imprudent. AIU complains that to disallow these severance costs sends a message to utilities that necessary and prudent workforce reductions will be punished financially. AIU asserts this would be a radical departure from past practice, where the Commission has recognized that utilities should not be punished for incurring short-term severance costs that produce long-term reductions in the cost of service.

According to AIU, in Docket No. 05-0597, the Commission approved amortization of severance costs incurred by ComEd in implementing its Exelon Way severance program, notwithstanding objections by the AG that these were one-time, nonrecurring costs. AIU asserts that the same is true here, where Staff's adjustment reflects the savings that will be realized from AIU's workforce reductions. AIU contends that the workforce reduction adjustment must be calculated net of severance costs, as shown in Ameren Ex. 51.9.

In addition to severance costs, AIU indicates that in its Initial Brief it identified three other corrections that should be made to Staff's workforce reduction adjustment. AIU says Staff made these three corrections. Specifically, Staff revised its rebuttal position so that incentive compensation costs are not double counted. Staff has also removed any double counting of payroll tax and used a rate of 7.65% to calculate the tax as agreed by AIU. It appears to AIU from Staff's schedules that Staff has also removed transmission-related costs from its adjustment. AIU says these matters are now uncontested.

c. Commission Conclusion

The Commission finds that in light of the fact that ratepayers will reap the long-term benefits of the workforce reduction program, it is fair for them to bear the costs associated with the program. Staff's proposal to disallow these costs is not fair and it is therefore rejected. The Commission adopts AIU's proposal to amortize the severance costs over three years.

8. Public Utilities Revenue Act Tax

The Public Utilities Revenue Act ("PURA"), 35 ILCS 620/1 et seq., levies a tax on electric utilities based on the total amount of energy delivered in a year at different rates for up to seven different kilowatt-hour ("kWh") sales blocks. Although all parties recognize that this tax is part of the cost of service and must be recovered in rates, this issue nonetheless produced several points of contention. AIU initially proposed to recover the PURA tax expense through a separate rider mechanism instead of through base rates, but has since withdrawn this proposal in the face of opposition from Staff and IIEC. AIU also proposes to allocate the PURA tax expense on a per kWh basis, rather than on the same basis as general plant, as is currently done. This issue is discussed elsewhere in this Order. The third area of contention concerns Staff and IIEC's proposed revenue requirement adjustment associated with the PURA tax and is discussed below.

a. AIU Position

AIU proposes a pro forma adjustment to restate test year expense associated with the PURA tax to be consistent with the use of weather-normalized kWh sales in the calculation of revenues at present rates. AIU states that weather normalized sales are then multiplied by current statutory tax rates to arrive at the pro forma amount for this tax. IIEC and Staff object to this adjustment because it does not account for refunds/credits routinely received by AIU for overpayment of the tax.

Based on the fact that AIU receives periodic refunds/credits and did not reflect these in its adjustment, AIU understands that Staff recommends that the pro forma adjustment should be eliminated in its entirety. AIU believes a more even-handed approach would be to simply correct the adjustment to reflect the refunds/credits, as IIEC proposes. AIU says that IIEC's approach adopts the use of weather normalized kWh sales applied to statutory tax rates. AIU claims that since these sales are used to calculate delivery service revenues, there is a matching of sales used to derive revenues with sales used to calculate expense. AIU believes that IIEC's approach has the added benefit of eliminating the impact of prior period adjustments to prior period accruals that may exist with the per-books distribution tax expense. AIU indicates that Ameren Ex. 51.13 reflects IIEC's approach and should be adopted as the basis for determining the recoverable test year electric distribution tax expense.

AIU explains that the calculation used by it and IIEC results in an increase over actual 2008 net costs because the AIU and IIEC approach eliminates the impact of any adjustments to prior period accruals that may exist with the per books PURA tax expense. AIU states that because the AIU and IIEC approach uses kWh sales to calculate delivery service revenues, there is a matching of sales used to derive revenues with sales used to calculate PURA tax expense. AIU claims that Staff's alternative proposal to take a —snapshot” of net 2008 costs ignores the impact of prior period adjustments, thereby creating a mismatch between test period revenues and expenses. AIU believes that its approach is the better one, and should be adopted in these proceedings.

b. IIEC Position

IIEC has recommended that AIU's test year revenue requirements reflect the impact of credits or refunds of the PURA tax to AIU during the 2008 test year to the extent such credits and refunds are not already reflected in the revenue requirement. AIU responds that a review of the history of the PURA tax indicates that AIU has received some level of refunds of this tax. AIU therefore agrees with IIEC's proposal to reflect the test year level of refunds as a reduction in AIU's requested revenue requirement. IIEC understands that AIU is recommending that the AmerenCILCO revenue requirement be reduced by $649,000, the AmerenCIPS revenue requirement be reduced by $638,000, and the AmerenIP revenue requirement be reduced by $2,686,000. Since these reductions are very close to the reductions recommended by IIEC witness Stephens, IIEC accepts AIU's proposed adjustment. IIEC has no position on whether an additional or further adjustment as proposed by the Staff is necessary.

c. Staff Position

Staff has proposed an adjustment to remove AIU's pro forma adjustment which weather-normalizes the PURA tax expense. Staff believes AIU has not shown that AIU's share of the statutory cap on the tax will increase during the period rates determined in these proceedings are in effect. Staff asserts that the amount of electric distribution tax for a given calendar year is a combination of the amount remitted quarterly by the utility based on a tiered structure of rates for delivery volumes as well as credit memoranda resulting from the statutory cap on the tax. Staff claims that AIU has received credit memos in each year for which information was provided. Staff contends that AIU's adjustment was simply based on the application of the tiered formula for computing the tax without considering the credit memos that are routinely received by AIU.

Staff acknowledges that AIU revised its adjustment to reflect the test year level of refunds (credit memoranda) as a reduction to the weather-normalized tax amount. While Staff agrees that this is an improvement over the initial proposal which did not reflect the refunds, Staff says it still results in an overall increase over the 2008 net costs, which Staff believes AIU has not demonstrated will occur. In the absence of a clear demonstration of an increase in its share of the PURA tax, Staff believes no increase in the expense is warranted.

d. Commission Conclusion

As the Commission understands it, the PURA tax is a function of kWh delivered by an electric utility, a tiered tax rate structure for different levels of kWh delivered, and credits or refunds from previous years that result from a statutory cap on the total tax collected from all electric utilities. It appears to the Commission that AIU's proposal, modified to reflect the credits or refunds, properly takes into consideration all of the relevant factors. The PURA tax is a function of kWh delivered, which will depend in part upon the weather. Why Staff objects to weather normalizing the PURA tax obligation is not clear to the Commission. Staff seems to suggest that the statutory cap on the PURA tax somehow influences its objection to AIU's proposed weather normalization adjustment. The Commission believes, however, that by incorporating the credits or refunds discussed above, this concern has been addressed. The Commission rejects

Staff's recommendation on this issue and finds that the calculation of the PURA tax that AIU and IIEC have agreed to should be used for purposes of this proceeding.

9. Transportation Fuel Expense

a. AIU Position

AIU's cost of service includes the cost of gasoline and diesel fuel used to operate fleet vehicles and construction equipment. AIU originally calculated its test year transportation fuel expense based on actual fuel costs for calendar year 2008. In light of Staff's concern that fuel prices have declined from levels reached during 2008 and to reduce the number of contested issues, AIU subsequently proposed that this expense be normalized for purposes of this proceeding by calculating AIU's average gasoline and diesel fuel costs over a three-year period from August 2006 through July 2009. AIU asserts that its normalization method captures the variation and fluctuations in prices that actually have occurred for gasoline and diesel fuel in recent years. As a result, AIU proposes a downward adjustment to its original request for fuel expense of approximately $367,000 for the gas utilities and $899,000 for the electric utilities.

Staff proposes that AIU's average fuel costs be calculated (and adjusted further downward) using prices from August 2008 through July 2009. AIU asserts that fuel expense is volatile and that any number of factors beyond the utility's control can cause fuel prices to fluctuate rapidly. AIU asserts that normalization of a volatile, fluctuating expense over a historical period accounts for volatility and smoothes out fluctuations. AIU complains that Staff's calculation of average fuel costs relies on a period of time that is too narrow and largely encompasses a decline in fuel prices in the second half of 2008 and depressed fuel prices during the first half of 2009. AIU insists that it is inappropriate to normalize a volatile and rapidly fluctuating expense item like transportation fuel costs by selectively relying on only a 12-month period of time where the prices in large part were abnormally low.

In response to Staff's claim that its method will be representative of future fuel costs, AIU argues that the Energy Information Administration's ("EIA") latest 2010 forecast issued in December 2009 shows an average price for gasoline 37¢ higher ($2.88 vs. $2.51) and for diesel fuel 18¢ higher ($2.96 vs. $2.78) than the average fuel prices in the 12-month period relied on by Staff. Using its proposed three-year period as the source for its adjustments, AIU believes that its proposal appropriately accounts for price fluctuations and volatility. AIU contends that its calculation captures not only the higher prices experienced in the first half of 2008, but also the lower prices experienced in the second half of 2008 and first half of 2009 that Staff relies on in its calculation. AIU states that even with the higher 2008 prices included in AIU's normalization, the average price of gasoline calculated by AIU ($2.83) is actually less than the average price of gasoline for 2010 based on the EIA forecast issued in December 2009 ($2.88).

AIU also contends that more often than not the historical period of time that is examined to normalize an expense is a number of years. AIU notes that Staff recommends a normalization adjustment to AmerenIP's test year expense for Account 887, Maintenance of Mains, based on a three-year average of historical expenses. In this instance, AIU does not believe that Staff's proposal even amounts to a normalization of the expense. Rather, AIU claims that Staff essentially proposes to shift AIU's 2008 test year period forward seven months, to August 2008 through July 2009, to mask the reality of higher fuel prices that occurred earlier in 2008. According to AIU, Staff's reliance on fuel prices from a different 12-month period of time is subject to the same criticisms that Staff makes concerning AIU's initial reliance on calendar year 2008 prices. AIU states that to rely on too narrow a window of time to calculate an average price of a volatile, rapidly fluctuating item can skew the average. AIU contends that in this instance Staff's reliance on prices from August 2008 to July 2009 not only masks the reality of higher prices that occurred earlier in 2008, but also gives too much weight to declining and depressed prices that occurred later in 2008 and 2009.

Despite its concerns about 2008 fuel prices, AIU observes that Staff itself relies on 2008 data in its proposed calculation of AIU's average fuel costs. AIU complains that Staff just selectively relies on fuel prices from the second half of 2008, when the United States was in the midst of an economic recession and fuel prices plummeted. AIU agrees that fuel prices rose during the first half of 2008 and then sharply declined in the second half. According to AIU, this does not mean that the low price period should be considered and the high price period ignored.

Staff further claims that the 2010 price forecast issued by EIA in October 2009 shows no trend for fuel prices in 2010 to return to levels reached in 2008. AIU asserts that even if 2010 forecasted prices prove that certain higher 2008 prices should be selectively excluded from the calculation of AIU's average fuel prices, EIA's short-term forecasts do not foreclose the possibility the fuel prices could rapidly rise in 2010. AIU claims that EIA's short-term price forecasts are issued and revised upward or downward on a monthly basis. According to AIU, these revisions can be significant. AIU says that comparing the EIA 2010 forecast issued in January 2009 to the one issued in October 2009 shows that, in the past few months, forecasted prices for 2010 already have been revised upward by an average of 21% for gasoline and 9% for diesel fuel.

AIU adds that comparing EIA's October 2007 forecast of 2008 prices to actual 2008 prices shows that EIA failed to predict a sharp increase in prices that actually occurred. AIU states that actual prices in 2008 were on average 15% higher for gasoline and 28% higher for diesel than prices EIA projected in the fall of 2007. Given the number of external variables that can cause the fuel prices to fluctuate rapidly, such as consumer demand, conflicts in oil producing regions, cuts in production by the Organization of Petroleum Exporting Countries, refinery capacity, and even hurricanes in the Gulf of Mexico, AIU argues that there can be no assurances that fuel prices will not vary significantly from the EIA October 2009 forecast relied on by Staff.

b. Staff Position

Staff recommends each AIU utility revalue its transportation fuel expenses using an average gasoline price of $2.51/gallon and an average diesel fuel price of $2.78/gallon. In response to Staff's concerns, AIU revised its initial position of using 2008 gasoline and diesel fuel costs to value its transportation fuel expense amounts and instead propose to use an average of fuel prices from August 2006 through July 2009. AIU's proposal is not satisfactory to Staff, who recommends using the average fuel prices from August 2008 through July 2009.

In formulating its position, Staff reviewed the EIA/Short Term Energy Outlook, U.S. Nominal Prices. Staff believes that gasoline and diesel fuel prices experienced in 2008 are not representative of gasoline and diesel prices on a going forward basis. According to Staff, the EIA 2010 price forecast for gasoline prices shows no trend of returning to the high costs AIU experienced in 2008, especially those gasoline prices in the $4/gallon range. Staff asserts there is, on average, a 61¢/gallon variance between the currently forecasted 2010 gasoline prices and those AIU experienced in 2008. Staff also contends that the EIA price forecast for diesel fuel in 2010 shows no trend of returning to the diesel prices reached in 2008, especially those diesel prices in the $4/gallon range which AIU utilized in its calculation of the average diesel fuel prices. Staff asserts that, on average, a $1.03/gallon variance exists between the currently forecasted 2010 diesel prices and those AIU experienced in 2008.

Staff says that AIU identifies three concerns regarding the gasoline and diesel fuel prices utilized in Staff's calculation of average fuel prices. First, AIU alleges that Staff's analysis arbitrarily chose fuel prices from August 2008 to July 2009. Second, AIU claims that fuel prices are volatile and fluctuating, and as a result, AIU recommends normalizing the average fuel price over the period of August 2006 to July 2009, versus Staff's one-year proposal. Finally, AIU asserts that the EIA short-term price forecasts are subject to frequent revisions.

Regarding AIU's first concern, Staff claims it did not choose the fuel prices arbitrarily. Staff states that it selected the most recent EIA data available at the time Staff filed its Direct Testimony. Staff believes AIU's claim that Staff's analysis arbitrarily applied fuel prices from August 2008 through July 2009 is unsubstantiated. Further, Staff asserts its recommendation yields a more accurate representation of fuel prices AIU will experience when rates established by the Commission go into effect.

In response to AIU's second concern, Staff does not dispute AIU's claim that transportation fuel prices are volatile and fluctuate. Staff, however, disagrees with AIU's proposal to utilize a three-year average to normalize those prices. Staff states that AIU's proposal relies too much on 2008 transportation fuel prices that happen to be the highest experienced by AIU. Staff believes that the inclusion of these costs would result in an overstatement of costs attributed to transportation fuels on a going forward basis.

With respect to AIU's third concern, Staff does not dispute AIU's claim that EIA updates its forecasts frequently. Staff recognizes that EIA provides monthly updates. Staff contends that any forecast of future events will have inaccuracies. In Staff's view, AIU's observation that significant differences have occurred between actual and forecasted EIA information ignores this basic fact. Staff asserts that AIU's selective comparison points out some of the highest differences between EIA's short-term forecasted prices and actual fuel prices, but does not change what the current forecast shows. Staff suggests that no one knows if major events, such as a hurricane or any other event, could influence those prices in the near future. Staff contends that the current and best information available regarding future transportation fuel costs supports Staff's recommendation.

AIU claims that the average gasoline and diesel fuel prices that it proposed are more closely in line with the latest EIA forecasts than the average gasoline and diesel fuel price proposed by Staff. Staff does not dispute that the December 2009 EIA forecasts for 2010 prices for gasoline and diesel fuel rose slightly since Staff filed its Rebuttal Testimony. Staff says it used the August 2009 EIA forecasts to show that AIU's 2008 transportation fuel prices were price outliers. In Staff's view, the December 2009 EIA forecast for transportation fuel prices in 2010 still demonstrate that AIU 2008 gasoline and diesel fuel prices are outliers, which Staff claims support its arguments.

AIU argues that since its proposed transportation fuel price more closely resembles the average gasoline and diesel fuel prices forecasted by EIA in December 2009 for calendar year 2010 than Staff's proposed prices, the Commission should adopt its proposal. Staff states that AIU selected a historical test year where only known and measureable changes are considered. According to Staff, forecasted fuel prices are not known and measureable. Staff contends that the actual 2009 prices that were included in the EIA December 2009 report are what is known and measurable. Staff states that this report showed the actual average price data for transportation fuels for January 2009 to December 2009 was $2.40/gallon for gasoline and $2.47/gallon for diesel fuel. Staff claims these values more closely correspond to Staff's proposed numbers, $2.51/gallon and $2.78/gallon, then AIU's proposed prices, $2.88/gallon and $2.96/gallon, respectively.

Staff also denies that 12 months is too short of a period to use as the basis for normalizing costs. Staff relates that it recently relied on 12 months of EIA data to value transportation fuels in the Peoples and North Shore rate cases in Docket Nos. 09-0166 and 09-0167 (Cons.). With regard to its adjustment for Account 887 based on a three-year normalization period, Staff denies there is any inconsistency with the 12-month period it proposes for fuel costs. Staff claims that its proposal regarding Account 887 is unique to the circumstances associated with that issue.

Staff reports that use of its proposal would result in a reduction in O&M expense for each utility as follows: AmerenCILCO, $27,000 (gas) and $180,000 (electric); AmerenCIPS, $51,000 (gas) and $494,000 (electric); and for AmerenIP $72,000 (gas) and $560,000 (electric).

c. Commission Conclusion

AIU proposes to normalize gasoline and diesel fuel costs over a three year period from August 2006 through July 2009. In contrast, Staff proposes to average fuel prices from August 2008 to July 2009. The Commission is concerned that AIU's methodology utilized in calculating transportation fuel costs could lead to fuel prices that are unreasonably high.

It is not entirely clear how AIU decided that the three-year period from August 2006 to July 2009 was the appropriate period for measuring fuel prices, whereas Staff provided a reasonable basis for its selection. Consequently, of the two proposals in the record, the Commission finds that a twelve month average is superior to AIU's proposed three year average. For purposes of this proceeding the Commission concludes that Staff's method for measuring fuel costs, and the results thereof, should be approved.

10. Account 887, Maintenance of Mains

a. AIU Position

In order to render safe, adequate, and reliable gas delivery service, AIU says it must perform both routine and special maintenance on gas distribution mains. The distribution expenses associated with these gas maintenance activities are collected in FERC Account 887, otherwise known as the ―Maintenance of Mains" account. AIU indicates it initially requested recovery of approximately $4.981 million in expenses for AmerenIP's Account 887 for the 2008 test year. In response to Staff's objection that expense in this account has trended upward in recent years and to limit the number of contested issues, AIU says it subsequently proposed, for purposes of this proceeding only, to normalize expense for this account using amounts for a three-year period ending September 2009. As a result, AIU indicates that in rebuttal it requested recovery of only approximately $3.78 million in expense for this account, which represents a downward adjustment of $1.201 million from the amount initially requested.

AIU reports that Staff rejects the proposed use of more recent 2009 data to normalize expense for AmerenIP's Account 887. Staff asserts that AIU is unable to explain or provide any basis for why the costs in this account have increased from 2006 through 2008. AIU says Staff claims that AIU's testimony and responses to data requests failed to provide any supporting data that demonstrated that the dramatic cost increases to Account 887 between 2006 and 2008 were just and reasonable. AIU contends that in responding to AIU's normalization approach in rebuttal, Staff fails to explain why more recent actual 2009 data should not be used in the calculation of an average expense for this account. According to AIU, Staff continues to maintain that AmerenIP's Account 887 expense should be averaged using older expense data from calendar years 2006-2008. As a result, Staff requests an additional downward adjustment of $665,000 for this expense compared to AIU's rebuttal request.

AIU indicates that it disagrees in principle with Staff's approach to selectively review and normalize the expense for one account based on prior period spending simply because the test year expense for that account may be higher than in previous years. AIU contends that such an approach fails to consider that costs associated with a utility's recurring business activities can impact any particular account differently from year to year. AIU insists that it is neither unreasonable nor unexpected for a utility's maintenance expense to vary annually depending on the type and number of projects required to repair damaged distribution infrastructure, replace obsolete assets, and expand systems to meet customer demands and improve reliability of service.

AIU asserts that comparing the expense for Account 887 for the 12 months ending September 2008 ($4.318 million) and September 2009 ($4.451 million) confirms that the 2008 test year expense is not an abnormally high amount. In AIU's view, the 2009 data confirms that the expense associated with this account is trending upward. Despite this upward trend, AIU says it seeks recovery of only $3.780 million. AIU claims that the 2009 data confirms that test year expense is representative of the level of expense that AIU will incur in 2010, when rates set in this proceeding will be in effect. In AIU's view, there is no doubt that costs in Account 887 increased from 2006 to 2008. The mere fact that expense for Account 887 has increased in recent years, AIU contends, does not establish that the test year expense is unreasonable.

AIU also disagrees with Staff's assertion that it is unable to explain or provide any basis for the increase or failure to provide any supporting data to demonstrate that the increase is ―just and reasonable." AIU claims it identified the specific costs that contributed to the increase in expense in this account and has explained that the increase was largely due to increased costs for union and management labor and labor relating loadings. AIU argues that it is neither unreasonable nor unexpected for AmerenIP's maintenance expense to trend upward based on incremental increases in costs associated with labor and inflation. AIU believes Staff is mistaken to suggest that AIU has not provided any basis or explanation for the increase in expense.

In response to AIU's proposal to include 2009 data, AIU claims Staff repackages its complaints that AIU has not supported the reasonableness of the 2008 test year expense. According to AIU, Staff fails to explain why use of more recent data in the averaging calculation is not appropriate, especially when Staff has used 2009 data when proposing adjustments for other expenses. AIU states that Staff relied on 2009 pricing data to calculate AIU's average fuel costs, but failed to rely on 2009 data in making the proposed adjustment to AmerenIP's Account 887 expense.

In AIU's view, Staff's argument, when boiled down, is that 2009 data can not be used to normalize the expense because AIU has not demonstrated that the 2008 expense is just and reasonable. AIU says Staff includes 2008 in its normalization calculation. AIU believes that if it is appropriate to use 2008 expense amounts in the calculation, it is also appropriate to use 2009 data. AIU contends that Staff's argument misses that point and clouds the issue of the appropriate normalization period by recanting Staff's complaints about the level of test year expense.

AIU states that it agreed to normalize the expense in AmerenIP's Account 887 over a number of years to satisfy Staff's concern that the expense for the 2008 test year is somewhat higher than in previous years. AIU argues that Staff's proposal to use older, outdated data in the calculation of an average expense for this account unreasonably increases the adjustment to the 2008 test year expense proposed by AIU. AIU states that rates are set prospectively, not retroactively, so what the expense was historically for this account is not as relevant as what the expense is now and what it will be going forward. Accordingly, AIU urges the Commission to accept its proposal to normalize this expense based on data from the three-year period ending September 2009.

According to AIU, Staff does not address the accuracy of the 2009 data at all. Instead, AIU continues, Staff argues that because 2008 costs were allegedly excessive, 2009 data should be ignored. AIU believes this makes no sense. AIU contends that recognition of 2009 data actually serves to validate the reasonableness of 2008 costs. In AIU's view, this issue does not center on the reasonableness of 2008 data, since both Staff and AIU include 2008 in its calculation of normalized test year expense. Rather, the issue centers on whether more recent actual 2009 data, under AIU's proposal, or older 2006 data, under Staff's proposal, should be included in the calculation to normalize test year expense. AIU contends that Staff's proposal to adjust downward AIU's normalized test year expense should be rejected.

AIU says Staff has endorsed the use of 2009 data in making adjustments to other test-year expenses such as tree trimming, uncollectibles, and storm expenses. AIU points out that Staff witness Seagle refuses to use 2009 data when calculating the adjustment to AmerenIP's Account 887 expense even though he relies on 2009 data to calculate adjustments for AIU's transportation fuel costs and company-use and franchise gas amounts. AIU claims that Staff's approach of selectively excluding 2009 data in this instance from its calculation of an average expense without explanation is neither appropriate nor consistent with its treatment of normalizing other operating expenses.

b. Staff Position

Staff reports that AmerenIP's requested expense for its Account 887 is higher in the test year than in any other period reviewed for this account. Further, Staff alleges AmerenIP was unable to explain why Account 887 had experienced such a large increase from historical periods. As a result, Staff recommends that the Commission average AmerenIP's Account 887 expense amount over the three-year period spanning 2006 through 2008. In response to Staff's recommendation, AmerenIP proposed to use the most recent three-year period of actual experiences to value this account. Staff disputes this proposal due to AmerenIP's inability to demonstrate the just and reasonableness of its requested value.

Staff observes that AmerenIP's Account 887 expense amounts more than doubled between 2006 and 2007 and then increased significantly between 2007 and 2008. Staff calculates that there was a 259% increase in expenses over a three-year period. Staff states that while AmerenIP provided a list that identified each cost that contributes to the large increase from 2007 to 2008, Staff claims AmerenIP could not provide any meaningful explanation regarding the increase. Staff says that AmerenIP attributes the increase in costs associated with this account to increases in labor and labor related loading. Staff complains that AmerenIP also indicated that it is unable to track costs passed through Account 887 due to "so many activities and variables" and ―operational reasons." Staff finds AmerenIP's explanation unacceptable. Staff argues that AmerenIP must demonstrate that the costs it proposes to pass on to ratepayers are just and reasonable.

Staff explains that it limited its comparison to the last three full calendar years because AmerenIP was transitioning to AIU's accounting system in 2005 and prior to 2006 used a different accounting system. Staff asserts that the Account 887 expense from the period prior to 2006 was approximately the same or less than the 2006 amount.

Staff disputes AIU's assertion that it provided a detailed explanation of why Account 887 expense has increased so dramatically from 2006 to 2008. Staff says it issued multiple data requests that attempted to establish what, if any, business activities had changed between 2006 and 2008 and how that impacted Account 887. Staff argues that AIU's testimony and responses to its data requests were insufficient for Staff to determine if AmerenIP's Account 887 expense was just and reasonable.

c. Commission Conclusion

As an initial matter, the Commission must be clear that dispute concerns only AmerenIP's gas operations. To normalize AmerenIP's Account 887 expenses, AIU proposes to use the three-year period ending September 2009. Staff proposes to use the three-year period ending December 2008. The table below shows the proposals of both AIU and Staff.

AIU's Proposal		
2,572,000		12 months ended September 2007
4,318,000		12 months ended September 2008
4,451,000		12 months ended September 2009
$ 3,780,333		Average

Staff's Proposal		
1,388,100		Calendar 2006
2,976,633		Calendar 2007
4,980,993		Calendar 2008
$ 3,115,242		Average

As noted above in the Commission's discussion of the value of gas in storage to be included in rate base, the Commission is somewhat frustrated with the various measurement periods selected by AIU and Staff in this proceeding. In this instance, both AIU and Staff make interesting statements about their own proposal and that of the other entity. It is not clear to the Commission that either is entirely correct. As a result, the Commission finds that for purposes of these proceedings, AIU's proposal and Staff's proposal should be combined to determine the level of Maintenance of Mains to include in AmerenIP's operating expenses. Averaging AIU's proposal and Staff's proposal produces a value of $3,447,788, or a reduction of approximately $332,000 from AIU's proposal. The Commission hereby finds that this value should be reflected in AmerenIP's operating expenses.

11. Injuries and Damages Expenses

a. AIU's Position

AIU indicates that its cost of service includes payments made to settle injury and damage claims. Because this expense fluctuates from year to year, AIU proposes to normalize this expense for the test year. AIU's normalization approach uses a five-year average (calendar years 2004 through 2008) of actual payments for injury and damages claims (four years in the case of AmerenIP to eliminate an outlier year), adjusted for inflation using the consumer price index ("CPI"). According to AIU, the only point of contention with respect to AIU's normalization approach is the use of an inflation factor in calculating the historical average. Elimination of an inflation factor would reduce the total electric revenue requirement by $673,000 and the gas revenue requirement by $129,000.

AIU indicates that IIEC is the only party to argue that the AIUs' normalization method should not include an inflation component. IIEC claims that the use of an inflation factor is improper because the absence of an inflation factor has not caused these fluctuations. Instead, IIEC asserts that the logical assumption is that the fluctuation in these charges would be a function of the number of claims settled during and calendar year and the size of the claims settled in the year. In AIU's view, IIEC misses the point. AIU states that no one disputes that injuries and damages expense fluctuates from year to year. AIU suggests that smoothing out these fluctuations is accomplished through the use of a four- or five-year average. AIU adds, however, that calculating a mathematical average of historical claims experience fails to account for the fact that today's dollars purchase fewer goods and services than dollars in years past. AIU states that inflation is the rise in the general level of prices over a period of time. When inflation rises, AIU says a dollar purchases fewer goods and services. Assuming a positive level of inflation between 2004 and 2008, AIU indicates a dollar would be worth less today than it was worth in 2004.

AIU contends that while its proposed normalization calculation properly recognizes the affect of inflation, IIEC‘s adjustment does not. AIU notes that the inflation adjustment has not been opposed by Staff and is consistent with the treatment of normalized storm expense, which AIU describes as another volatile expense analogous to injuries and damages that Staff and AG/CUB have endorsed in these proceedings. By ignoring inflation, AIU alleges that IIEC‘s calculation understates injuries and damages expense and should be rejected.

According to AIU, IIEC suggests that the Commission should adhere to an alleged —customary, systematic approach" to determining injuries and damages expense; i.e., without an inflation adjustment. AIU says it is unaware of any —customary, systemic" approach for calculating this expense. AIU asserts that this is the first case in which AIU has requested an inflation adjustment for injuries and damages expense. Because the Commission has not previously addressed whether an inflation component is appropriate, AIU believes it can hardly be said that the Commission has developed a —customary, systemic approach" on this issue.

AIU argues that regardless of what the Commission ordered in prior proceedings, the record in this proceeding supports the use of an inflation factor. AIU contends that IIEC attempts to ignore the fact that goods and services cost more today than they did in the past by arguing that the proper focus of the injuries and damages expense item is not the level of time and material costs of the construction or other activities that may give rise to personal injury or property damage claims. Rather, IIEC says injuries and damages expense covers the costs of resolving the claims themselves. AIU claims that lost in this argument is any recognition of the fact that the —cost of resolving the claims themselves" will be higher in 2010 than in 2004 because of inflation. In AIU's view, the claim that it presented no evidence that would establish a relationship between the actual costs of resolving claims and the inflation of construction materials and labor costs is unfounded. AIU insists that any claim that requires AIU to compensate someone for damage to person or property will necessarily be higher today than in 2004, because labor and material costs are more expensive today than in 2004 due to inflation.

b. IIEC Position

IIEC opposes AIU‘s addition of an inflation adjustment to what it describes as the consistent, systematic approach to annualizing injuries and damages expenses the Commission has employed in at least the last two AIU rate cases. IIEC claims that continued use of the Commission‘s customary, systematic approach will allow recovery of injuries and damages expenses at a level that reflects AIU‘s actual expenses. In

IIEC's view, modifying that level of expense using a CPI factor is unnecessary and inappropriate.

IIEC reports that AIU accepted Staff's proposed adjustment to remove certain hazardous materials costs from the calculation of normalized injuries and damages expense. IIEC asserts that the acceptance of Staff's modification does not eliminate AIU's inflation adjustment, and it does not change IIEC's opposition to the inflation adjustment.

IIEC believes AIU's proposed adjustment is inappropriate for at least two reasons. According to IIEC, AIU claims the purpose of the inflation factor is that the underlying materials or labor costs giving rise to historical claims payments would cost more today than they did five years ago. IIEC argues that the proper focus of the injuries and damages expense item is not the level of time and material costs of the construction or other activities that may give rise to personal injury or property damages claims. Rather, IIEC contends that the injuries and damages expense covers the costs of resolving the claims themselves. IIEC asserts that if the simplistic relationship assumed by AIU's adjustment actually existed, there would be few disputed injuries and damages claims. IIEC suggests AIU could simply pay time and material costs for affected persons and property, rather than using investigations, negotiations, and litigation to minimize those expenses.

IIEC also contends that the factual assumptions underlying AIU's adjustment are not supported by any record evidence. AIU claims the assumed, but unproven, relationship noted above is the prime example. IIEC asserts that the level of actual injuries and damages expense incurred in a year is more closely related to the number of claims filed and subsequently settled during a year. With respect to the costs of the claims, IIEC insists that inflation is not a significant driver. Furthermore, IIEC claims use of the inflation factor also has no effect or impact on the number of claims processed. Faced with IIEC's challenge to the sole stated basis of its proposal, IIEC says AIU presented no evidence that would establish a relationship between the actual costs of resolving claims and the inflation of construction materials and labor costs.

IIEC states that there are significant fluctuations in the levels of injuries and damages expenses from year to year. In IIEC's view, such fluctuations, that are distinct from the rate of inflation, add support to IIEC's view that inflation is not a driver of this category of expenses. IIEC claims that applying the proposed adjustment for a factor (inflation) that has no demonstrated relationship to the fluctuating expenses could distort (increase) the level of expenses included in ratemaking expenses.

According to IIEC, AIU presented no quantitative evidence that the effects of inflation are not adequately reflected in the amounts for which it was able to settle injuries and damages claims or in the Commission's traditional normalization through a multi-year average. IIEC complains that AIU provided no analysis or other evidence showing that AIU has actually experienced any under-collections of this expense over the period the Commission has used a multi-year average that is not adjusted for inflation.

IIEC asserts that test year ratemaking rests on an assessment of a utility's costs and revenues over a consistent time period -- the test year. In this case, IIEC says AIU proposed an historical test year, 2008. Data from post-test year periods can be considered only if they meet the requirements established by the Commission's rule on post-test year adjustments. IIEC says Section 287.40 prohibits the use of attrition or inflation factors.

According to IIEC, the evidence of record does not support the assumptions on which AIU's request depends. AIU argues that all other things being equal, if it cost $100 to settle a claim in 2004, it would cost more than $100 to settle that same claim in 2010, when rates in this proceeding go into effect. IIEC asserts that while that argument depends on —allother things being equal," AIU has presented no evidence that all other things will be held equal. IIEC suggests that through safety programs to prevent claims and through investigations, negotiations, and litigation to reduce the cost of claims that do occur, AIU is presumably working to assure that all things are not equal.

c. Staff Position

Staff recommends that the Commission accept its proposed adjustment to the AIU test year injuries and damages expense for AmerenIP to remove the effects of HMAC costs from the normalized level. Staff relates that AIU accepts its proposed adjustment. Staff notes that IIEC agrees with normalizing the level of injuries and damages expense, but takes issue with adjusting each year's costs for inflation using the CPI index, arguing that the fluctuations in the cost level from year to year was a function of the number of claims and the size of the claims processed in any given year. Staff says that AIU counters that argument by claiming that the inflation factor is not meant to level out the fluctuations in cost, but rather to reflect the increases in costs from year to year for materials and labor associated with those claims. Staff does not take issue with the use of the CPI Index in AIU's calculations.

d. Commission Conclusion

Because costs associated with injury and damage claims fluctuate from year to year, AIU proposes to normalize this expense for the test year. AIU's normalization approach uses the annual average from the years 2004 through 2008 of actual payments for injury and damages claims (four years in the case of AmerenIP), adjusted for inflation using the CPI. IIEC opposes the adjustment for inflation, arguing that AIU has not shown that inflation affects injury and damage claim costs. Staff proposes an adjustment to AmerenIP's injuries and damages expense, which AIU accepts.

This is the first case in which AIU has requested that an inflation factor be included in the normalization of injuries and damages expense. In the Commission's view, AIU's argument for including an inflation factor in the calculation is based on two premises, that inflation causes the cost of labor and materials to increase over time and that injuries and damages expenses are a direct function of labor and materials costs. It appears that IIEC essentially challenges the second premise, arguing that injuries and damages expenses are not a direct function of labor and material costs. The Commission concludes that AIU has not established that injuries and damages expenses are a direct function of labor and material costs. While it seems quite logical that such costs would, in some way, contribute to the injuries and damages expenses, there could well be other factors, which are independent of inflation, that also influence injuries and damages expenses. The Commission, therefore, adopts IIEC's recommendation that the inflation factor be excluded from the normalization calculation of injuries and damages expenses in these proceedings.

12. Overall Reasonableness of O&M Expenses

a. AIU Position

AIU states that in prior rate proceedings, parties have expressed concern to the Commission that AIU has not been effective in controlling certain of its O&M expense levels. In connection with filing these rate cases, AIU retained Concentric, a management consulting and economic advisory firm focused on the North American energy and water industries, to compare AIU's O&M expenses (electric and gas companies) to those of other utilities. AIU witness Amen, a Vice President with Concentric, used the peer-group approach to benchmark AIU's O&M expenses against those of other utilities. Specifically, Mr. Amen took the most recent data available to Concentric – FERC account level data for calendar year 2007 obtained from Federal Energy Regulatory Commission ("FERC") Form 1 and Form 2 filings – and analyzed the data through what AIU describes as a series of objective, comprehensive studies by benchmarking AIU's actual O&M expenses against other electric, gas, and combination utilities.

AIU states that the results of his 16 peer-group benchmarking studies led Mr. Amen to conclude that AIU's O&M expenses, including its A&G expenses, are on average lower than the majority of other gas, electric, and combination utilities. According to AIU, these studies demonstrate that AIU effectively controlled O&M expenses because it consistently performed better than its peers on a cost per customer basis. AIU contends that based on these results, the Commission can take comfort that AIU has been effective in controlling it O&M expenses at reasonable levels.

AIU asserts that the peer-group benchmarking approach produces studies that are objective, straight-forward, verifiable, replicable, and relevant to AIU. AIU also claims these types of studies are also often filed with regulatory commissions as an indicator of the reasonableness of a company's expenses. AIU suggests that this approach should be relied upon by the Commission in these proceedings as in the last rate case. AIU contends that the studies are objective because they include all costs for all companies that meet the parameters of the peer group being examined. AIU says no costs or companies are excluded subjectively or arbitrarily; if a company meets the parameters of the study, AIU says it is included.

AIU claims the studies are straightforward because by viewing the results of the studies, the Commission can easily understand how each of the three Ameren operating companies individually and collectively compare to other utilities. AIU says the results of each of the studies are graphically presented in an accessible exhibit. AIU states that if any of the three utility's performance did not compare well to its peers, the study and the corresponding exhibit would clearly reflect that fact. AIU contends that the studies are easily verifiable and replicable because they use information from the Form 1 and 2 annual reports filed with FERC by each of the peer group companies. AIU says it compiled this information and reported it without adjustment.

AIU states that through the use of relevant parameters, a researcher can create peer groups that consist of companies with similar operating characteristics. AIU suggests that comparisons can then be made as to the cost performance of each of the companies that meet the characteristic or parameter being studied. AIU says Mr. Amen created and compared peer groups consisting of gas, electric, and combined utilities, as AIU fits these parameters. AIU indicates that he also benchmarked Midwestern gas and electric companies as well as companies of sizes comparable to AIU and comparable breadth of services (e.g., whether the utility owns generation.) By accounting for all of these characteristics in various peer groups, AIU believes that Mr. Amen‘s studies aptly illuminate AIU‘s cost performance.

AIU contends that the peer-groups consist of a sufficient number of peers, which serve as the basis to evaluate AIU‘s cost performance. AIU contends that a peer group consisting of roughly 10 peers is adequate; the peer groups in Mr. Amen‘s studies ranged from nine to 205 peers. AIU says that while there is no single peer group containing companies with all of the same attributes against which to compare AIU‘s cost performance, Mr. Amen constructed 16 different peer groups, taking account of differences associated with size, geographic location, and the fact that AIU owns no regulated generation. Collectively, AIU asserts that Mr. Amen‘s peer-groups adequately account for the operating characteristics of AIU, and include more than a sufficient number of peers from which Mr. Amen could make robust and relevant findings about AIU‘s cost performance.

For his studies, Mr. Amen collected total A&G expense amounts and customer counts for peer companies. AIU says the costs included in the ten benchmarking analyses are unadjusted and reflect the amounts as reported in all peer companies‘ respective FERC Form 1 and 2 annual reports. AIU indicates that Mr. Amen took this information and unitized the costs on a per-customer basis to compare the AIUs‘ A&G expenses per customer to those of other utilities. AIU states that Mr. Amen prepared ten different iterations of the analyses to make the peer group of utilities more comparable to the characteristics of AIU.

According to AIU, Mr. Amen's ten studies show that AIU's A&G expenses compare favorably to the peers with similar operating characteristics. Mr. Amen included the following peer groups in his A&G expenses benchmark analysis: (1) electric utilities, (2) electric utilities in the Midwest, (3) electric utilities that own no generation, (4) electric utilities in the Midwest that own no generation, (5) similarly sized electric utilities that own no generation, (6) combination utilities, (7) combination utilities that owned no generation, (8) gas utilities, (9) gas utilities in the Midwest, and (10) similarly sized gas utilities in the Midwest. AIU asserts that for nearly all of these peer groups, the three Ameren operating utilities – both individually and collectively – operated at or below the mean and/or median costs of their peers. AIU claims that these peer-group benchmarking studies demonstrate that AIU has effectively controlled A&G expenses during calendar year 2007, and AIU's A&G expenses per customer compare favorably to those of other electric, gas, and combination utilities.

AIU says Mr. Amen expanded his analysis to include studies of AIU's total O&M expenses. AIU argues that unlike Mr. Fenrick's ―total O&M" study, Mr. Amen's six O&M studies analyzed all relevant O&M costs (including transmission, distribution, customer care, and A&G expenses) with the exception of total electric power production and total gas production expenses. AIU states that like his A&G studies, Mr. Amen's O&M studies compared AIU's O&M expenses per customer to several similarly situated peer groups: (1) electric utilities, (2) gas utilities, and (3) combined utilities.

AIU asserts that the total O&M studies confirmed what Mr. Amen had found with respect to the A&G studies: the three Ameren utilities – both individually and collectively – performed at or below the mean and median expenses of their peers. AIU says Ameren Ex. 32.1 shows the results of the study of the total electric O&M per customer for each of the electric utilities that filed a Form 1 with the FERC; the AIUs individually and collectively perform at or below the mean and the median of the 145 companies under review. According to AIU, Ameren Ex. 32.1 shows the peer group mean was $403.94 per customer, while the median was $388.45; AIU's total O&M cost per customer was below both the mean and median at $348.64.

AIU states that for the gas utilities, Ameren Ex. 32.2 shows that AmerenCILCO, AmerenIP, and the combined Ameren utilities were all below both the mean and the median of the peer group, which consisted of 192 gas companies. According to AIU, the only variance in performance related to AmerenCIPS, which when compared to gas only companies fell below the mean, but slightly higher than the median of the peer group.

Ameren Ex. 32.3 shows the results of the benchmarking study of combined total electric and gas companies' O&M expenses. AIU says that in this study, AIU ranked well below both the mean and the median of the peer group, which consisted of 42 combination utilities. Finally, AIU says that to compare labor cost efficiency among combination utilities like AIU, Mr. Amen studied the number of customers per employee. This metric serves as a check of the efficiency with which each company provides service to its customers. AIU asserts that in this study, AIU compared very favorably to the peer group of other combination utilities. The three Ameren utilities, individually and collectively, ranked between 4th and 14th out of a peer group of 89 electric and diversified utilities. AIU reports that AmerenCILCO had 701 customers per employee, AmerenCIPS had 864, and AmerenIP had 888, and that collectively they had 835. AIU indicates that the mean of the peer group was 446 and the median was 382.

Rather than critique the results of any specific study of Mr. Amen's, AIU states that AG/CUB witness Fenrick largely focuses on his alternative study, an econometric or translog cost model that purports to statistically predict AIU's A&G and distribution and customer care ("D&CC") expenses. AIU states that AG/CUB suggests that the results of Mr. Fenrick's study can be relied upon as a basis to show why AIU is not entitled to any rate increase. AIU contends, however, that even Mr. Fenrick admits that his statistical study should not be used to establish an authorized level of AIU-related expenses.

AIU argues that Mr. Fenrick's complex study suffers from substantial deficiencies and errors. AIU claims his study is deficient because Mr. Fenrick discarded numerous alternative models that he researched and created. AIU alleges that these alternative models contained data and information that were an integral part of his research process that led to Mr. Fenrick's final model. AIU says it is not possible to understand Mr. Fenrick's criteria for selection of the variables in his model without production of the process followed to arrive at his opinions. As neither AIU nor the Commission have access to that process, AIU argues any conclusion regarding O&M cost efficiency should be rejected for that reason alone.

AIU also complains that Mr. Fenrick's study contains numerous specification errors. AIU asserts that correcting some of the errors in Mr. Fenrick's study leads to material changes in his results that are qualitatively similar to the results of Mr. Amen's peer-group benchmarking studies. AIU alleges that the flaws in Mr. Fenrick's study notwithstanding, the only conclusion supported by the statistical properties of his model is that AIU is, at worst, an average cost performer.

Furthermore, AIU states that the specification of an econometric model includes formulating a mathematical equation by selecting appropriate variables to be used in the equation. AIU alleges that in so doing, Mr. Fenrick has committed two common specification errors: (1) the omission of relevant variables; and (2) the inclusion of irrelevant variables. According to AIU, these specification errors bias the results of Mr. Fenrick's econometric cost model, rendering it an inappropriate basis for drawing any conclusions. As an example of the first error, AIU believes it is significant that Mr. Fenrick omitted total sales as an output variable in his A&G model. AIU claims that using total sales as a measure of output in Mr. Fenrick's model yields results that are qualitatively similar to the results of Mr. Amen's peer-group benchmark for A&G expenses. According to AIU, using total sales instead of net generation and making no other changes to Mr. Fenrick's A&G model, the model suggests that AIU's A&G expenses compare favorably to the other utilities in Mr. Fenrick's study.

AIU alleges that another specification error is Mr. Fenrick‘s use of a wage level variable that is severely flawed. AIU states that Mr. Fenrick‘s study period is 1994 to 2007. AIU claims that despite the availability of data for this period, he used a single May 2008 wage level for each of the 115 companies in his study. AIU asserts that his wage metric implies constant real wages over a 14-year time period, as well as constant relative wages across regions. In using this wage level variable, AIU alleges that Mr. Fenrick incorrectly assumes that changes in wage rates over time and relative changes between regions can not be a cost factor. AIU insists that wage levels change over time and across regions of the country, even after adjusting for inflation. AIU alleges there are other problems with the wage information used by Mr. Fenrick.

AIU asserts that AG/CUB, like Mr. Fenrick, confuses correlation with causation. AIU states that it is important in a model of cost causation to distinguish between a factor that causes costs and a factor that is correlated with costs. AIU says if one factor causes cost, then the two are certainly correlated. AIU argues that just because two metrics move together does not mean that one caused the other, even if causation seems to make sense. AIU indicates that the choice of explanatory variables for a cost model must be based on sound economic theory. AIU contends that Mr. Fenrick has failed to provide a sound basis in economic theory for the cost models underlying his benchmarks.

According to AIU, when a 95% confidence interval is constructed around his estimated results, both of Mr. Fenrick‘s models fail to demonstrate that AIU‘s actual expenses between 2005 and 2007 are statistically significantly different from his estimated expenses. AIU asserts that Mr. Fenrick‘s estimated expenses, at which AIU would be operating efficiently, were statistically indistinguishable from AIU‘s actual expenses. AIU asserts that Mr. Fenrick has no basis for concluding that AIU is inefficient. Instead, AIU says the only conclusion supported by the statistical properties of Mr. Fenrick‘s model is that AIU is an average cost performer. AIU also criticizes the confidence interval analysis performed by Mr. Fenrick.

AG/CUB criticizes AIU because no one peer group can account for all the key variables that drive AIU‘s costs. AIU contends that is precisely why Mr. Amen constructed 16 different peer groups, each one taking into account certain of AIU‘s characteristics, such as size, geographic location, and the fact that AIU owns no generation. AIU says that collectively, these peer groups account for nearly all the operating characteristics that Mr. Fenrick concluded were significant drivers of expenses.

AIU disputes AG/CUB's statement that Mr. Amen‘s study did not account for economies of scale because his inclusion criterion was wide ranging (100,000 to 1,000,000 customers) enough to significantly distort the results. AIU says Mr. Amen prepared A&G peer group studies for gas and electric utilities within a range of customer counts that equaled the number of customers served by each of the Ameren utilities in Illinois. AIU states that AmerenCILCO serves approximately 206,000 electric customers and 212,000 gas customers, AmerenCIPS serves approximately 380,000 electric and 181,000 gas customers, and AmerenIP serves approximately 611,000 electric and 416,000 gas customers. AIU contends that Mr. Amen's peer groups with a range of 100,000 to 1,000,000 customers explicitly corrected for scale economies inherent in A&G expenses, contrary to AG/CUB's charge.

AG/CUB criticizes Mr. Amen for including a wide range of 145 utilities in his electric O&M cost per customer comparison. AIU says each of the companies that AG/CUB complains about are also included in Mr. Fenrick's econometric study. According to AIU, these companies were included because they met the all-electric-utility criteria of one of Mr. Amen's O&M studies. AIU says this study was meant to compare AIU to all electric utilities on an O&M cost per customer basis. AIU claims this industry-wide O&M study was submitted as part of Mr. Amen's rebuttal testimony after he submitted both industry-wide and attribute-specific A&G studies in his direct testimony, the results of which showed that AIU performed at or better than the majority of utilities in managing A&G expenses.

AG/CUB contends that Mr. Amen failed to account for the presence or absence of generation facilities. In response, AIU says Mr. Amen's studies explicitly addressed how AIU compared to utilities that did not own generation facilities. According to AIU, Mr. Amen prepared several studies specifically designed to compare AIU's A&G expenses per customer against all electric companies that owned no generation, Midwest electric utilities that owned no generation, and electric companies with between 100,000 and 1,000,000 customers that owned no generation. AIU insists that Mr. Amen's peer-group benchmarking study did account for the presence or absence of generation facilities.

AIU also understands LGI to make the following recommendations to the Commission: (1) monitor AmerenIP's annual maintenance and system improvement investments, (2) direct AmerenIP to identify, prioritize, and address the need to replace aged assets on a case-by-case basis, (3) direct AmerenIP to expedite its correction of existing NESC violations, and (4) continue to monitor the status of unresolved Liberty Report recommendations. AIU asserts that the recommendations offered by LGI in this proceeding, if approved by the Commission, would increase AmerenIP's capital expenditures and O&M expenses in 2010 and require AmerenCIPS and AmerenCILCO to spend less on their systems.

AIU says AmerenIP already provides Staff, on an annual basis, with data concerning its capital and O&M expenditures. AIU believes that introducing yet another level of monitoring of AmerenIP's expenditures is an unnecessary exercise and very likely a waste of resources. Despite LGI's claims, AIU insists AmerenIP's investment in its systems has not declined, nor is the reliability of its service threatened. AIU also says that AmerenIP already reports the book depreciation values of its distribution assets, as allowed under Section 411.120(b)(3)(G) of 83 Ill. Admin. Code 411, "Electric Reliability." AIU argues that requiring AmerenIP to identify and report on the physical age of each distribution asset is neither required nor warranted. AIU says it already regularly inspects the condition of its electric distribution assets. AIU contends that the method of age-reporting proposed by LGI does not allow AIU (or the Commission) to predict the future reliability of an asset. AIU claims it has already agreed with Staff on a timetable for inspecting its distribution networks and resolving NESC violations. AIU claims that requiring AIU to arbitrarily expedite NESC corrective actions in any one area of its operations, or at the expense of undertaking other capital investments and maintenance projects concerning AmerenIP‘s own infrastructure, would be inappropriate. AIU represents that it and Staff are in agreement that LGI's recommendations are unnecessary or inappropriate.

LGI complains that AmerenIP‘s investments have declined significantly from 2006. AIU responds that AmerenIP‘s capital investments in maintenance and system improvements have in fact increased between 2007 and 2009. According to AIU, LGI ignores that AmerenIP‘s expenditures, both its capital investments and O&M expenses, spiked in 2006 because of severe summer and winter storms. AIU also claims that LGI ignores the fact that AmerenIP invested heavily in its distribution infrastructure in 2004 through 2006 after Ameren acquired IP. AIU asserts that LGI witness Brodsky was hired to develop and evaluate AIU‘s audit of the AmerenIP electrical distribution systems. According to AIU, Mr. Brodsky acknowledges that AIU spent millions of dollars on system improvements to correct and upgrade those systems, including projects specifically requested by Champaign and Urbana that were identified and designed by Mr. Brodsky.

LGI further complains that AmerenIP‘s investments fall significantly behind that of AmerenCILCO and AmerenCIPS. AIU asserts that the data relied on by LGI concerning AIU‘s capital investments in maintenance and system improvements shows that, in the 2008 test year, the total capital dollars spent per customer were practically identical: $108.09 for AmerenCILCO; $107.98 for AmerenCIPS; and $105.00 for AmerenIP. AIU also asserts that LGI does not consider the typical fluctuations that occur in a utility‘s amount of investment on an annual basis because of extreme weather, circuit inspection findings, completion time of projects, and system enhancement needs. AIU also asserts that LGI does not consider the unique characteristics of the individual utilities, such as customer density, the makeup of the customer classes, or whether the utility services predominantly urban or rural areas, all of which impact the per customer investment levels of the individual utilities. AIU claims that LGI fails to consider other indicators of the reliability of a utility‘s service and systems, such as the utility‘s System Average Interruption Duration Index, Customer Average Interruption Duration Index, or Customer Average Interruption Frequency Index ratings or data concerning the utility‘s worst performing circuits. Even if LGI were correct that AmerenIP‘s investments in its systems are in decline or are lagging behind the other utilities, AIU argues that LGI has failed to conduct a sufficiently reliable study to identify AmerenIP‘s appropriate level of capital investment per customer or assess the overall reliability of AmerenIP‘s distribution network. AIU insists that it would be inappropriate to conclude on this record that AmerenIP‘s investments are lacking or that its service is unreliable.

AIU believes that LGI's recommendations for the Commission regarding AmerenIP‘s reporting of aging assets and expediting of NESC violations are similarly flawed and should be rejected. AIU states that it utilizes book depreciation, rather than actual physical age, when reporting the age of existing distribution assets. According to AIU, whether an asset has exceeded its book depreciation is not necessarily determinative of the asset's reliability. AIU contends that well-maintained distribution facilities/equipment can last well beyond the facility's assigned depreciable life. AIU says it utilizes a comprehensive circuit inspection program to identify and correct potential performance issues with their distribution assets. AIU says the method of age-reporting that the utility uses is not nearly as significant as the utility's inspection and maintenance practices. AIU also alleges that LGI knows that AIU does not have physical installation records for a significant portion of its distribution poles, transformers and conductors/cables, making it nearly impossible for AmerenIP to report the physical age of its assets.

b. AG/CUB Position

According to AG/CUB, econometrics combines economic theory with statistics to analyze and test economic relationships. AG/CUB asserts that experimental data is usually observational – that is, it examines one variable to infer an effect on a subject – rather than derived from controlled experiments. AG/CUB claims that in contrast, the field of econometrics has developed methods for identifying and estimating the impact of simultaneous variables that reflect the state of the market at any given time. AG/CUB says these methods allow researchers to make causal inferences in the absence of controlled experiments. Econometric benchmarking, AG/CUB continues, allows the researcher to create a target (a benchmark) for a given metric, in this case the O&M expense for an electric utility. AG/CUB asserts that this type of benchmarking approach offers a statistical perspective for the Commission to use in evaluating the performance of AIU in containing O&M expenses relative to comparable utilities.

AG/CUB asserts that effectively managing costs is an essential element of a well-performing utility. In a rate case such as this, what constitutes an appropriate level of O&M expense is often a contested issue. Absent market forces to provide the impetus for efficient operation, AG/CUB avers that regulators must provide diligent oversight of expenses in determining their just and reasonable levels. AG/CUB says O&M expenses are short-run costs upon which current management can assert the most immediate control. AG/CUB states that Mr. Fenrick's benchmarking study reviewed O&M costs in two categories: A&G and D&CC. AG/CUB believes AIU's recent performance in these cost areas is of considerable importance in the context of the current rate proceeding.

AG/CUB agrees with AIU that benchmarking is an important tool for the Commission to evaluate the reasonableness of AIU's costs and performance. AG/CUB suggests that regulators can use benchmarking when regulating electric reliability, determining appropriate cost or salary levels, evaluating energy efficiency attainment and goals, and in the escalation provisions of multi-year rate or revenue caps. AG/CUB also says that utility managers can also use benchmarking to determine overall performance within the industry, pinpoint areas where improvements can be made, set challenging yet achievable goals, and identify best practices.

Mr. Fenrick entered into his econometric benchmarking model the expenses of a sample of 115 U.S. investor-owned electric utilities, which created the target against which he compared AIU‘s test year spending. AG/CUB asserts that the data shows that once AIU‘s electric utility operations were compared to the sample utilities, AIU‘s actual costs consistently exceeded those of comparable utilities. AG/CUB asserts that AIU's benchmarking analysis is inferior to Mr. Fenrick‘s approach, as it fails to adequately adjust for one or more variables that Mr. Fenrick‘s research found to be significant cost drivers. AG/CUB believes the results of Mr. Fenrick‘s study and analysis provides additional support for the adjustments AG/CUB adopt in this proceeding.

Mr. Fenrick states that the role of benchmarking in energy utility regulation has grown. AG/CUB states that in 2009, Florida Power & Light ("FPL") and Oklahoma Gas & Electric sponsored benchmarking studies to display superior cost performance relative to the industry. AG/CUB indicates that FPL noted that it was consistent with both cost-based regulation and the long-standing latitude of regulators to recognize low-cost efficient service in setting an appropriate return. AG/CUB asserts that the Ontario Energy Board now requires annual cost benchmarking updates of all power distributors operating in Ontario, Canada, and allowed rate escalation is partially determined by benchmarking scores. AG/CUB states that in the early 2000‘s, AmerenUE filed benchmarking testimony defending the cost performance of its Missouri electric operations. AG/CUB says the AmerenUE report used econometric benchmarking techniques similar to the approach used by AG/CUB in this proceeding.

AG/CUB asserts that a performance cost benchmarking study like the one Mr. Fenrick conducted evaluates those management decisions involving input quantities and prices given the external conditions and constraints faced by utility management. AG/CUB says this allowed Mr. Fenrick to incorporate multiple variables believed to impact cost. This way, AG/CUB avers he could create statistically valid comparisons between a utility‘s actual performance and a customized expectation of those costs. AG/CUB says that in this instance, ―customized" means the model generates a custom expectation based on the comparison sample size and the number of variables accounted for in the model. AG/CUB asserts that good cost performers will have actual costs below the expected amounts, whereas poor performers will have actual costs above the expected amounts.

The goal of the econometric model, AG/CUB says, is to quantify expected costs in a fair and accurate way, accounting for the specific advantages and disadvantages inherent in the operating circumstances of each utility. AG/CUB asserts that the most accurate way to do this is to use regression analysis on each variable collected for each utility in the sample. In statistics, regression analysis is focused on identifying the relationship between a dependent variable and an independent variable. It illustrates how the typical value of the dependent variable changes when any one of the independent variables is varied, while the other independent variables are held fixed.

AG/CUB contends it can also, as it does with Mr. Fenrick's model, estimate what value the dependent variable would be given the independent variables used in the analysis - that is, the average value of the dependent variable when the independent variables are held fixed.

In Mr. Fenrick's analysis, the dependent variable was a utility's inflation-adjusted D&CC, or A&G, expense. The independent variables were the outputs (e.g., customers, volumes) and business condition variables (e.g., percent undergrounding, wage level, forestation) specific to each utility. AG/CUB says that to make sure that each independent variable included in the study did, in fact, affect the expense category, as he hypothesized when he included them, Mr. Fenrick conducted regressions and statistical testing to make sure that those variables were statistically significant cost drivers.

AG/CUB claims that the research shows that AIU's actual costs have consistently been above the model's expected costs for each Illinois utility in both of the examined O&M subcategories. For D&CC expense, AG/CUB states that AmerenCILCO, AmerenIP, and AmerenCIPS rank 76th, 80th, and 94th, respectively. AG/CUB claims that AIU's total D&CC expenses, across all three utilities, were 14.8% above what an average performing utility would be expected to spend under AIU's specific operating conditions. As compared to the top quartile of utilities, AG/CUB says AIU's D&CC expenses are approximately 35% above this standard. According to AG/CUB, the 2005-2007 A&G expenses even further exceed the model's prediction. For A&G spending, AG/CUB claims AmerenCILCO, AmerenIP, and AmerenCIPS rank 105th, 95th, and 85th, respectively. AG/CUB says the model showed expenses were 27.2% above expected spending for an average performing utility and about 48.6% above a top quartile performance standard.

AG/CUB contends that AIU's proposed test year expenses exceed normal cost increase expectations. To estimate AIU's performance in 2008 as compared to the sample utilities, Mr. Fenrick took the AIU's average annual cost performance in 2005-2007 and added the change in cost performance of AIU's proposed 2008 test year expenses. Mr. Fenrick first compared the AIU's actual 2005-2007 expenses to those proposed for the 2008 test year and calculated the percentage increase. AG/CUB says the percentage increases for the 2008 test year compared to the 2005-2007 average for AIU was about 31% for D&CC expenses and 24% for A&G expenses. According to AG/CUB, Mr. Fenrick then estimated the expected level of cost increases from 2005-2007 to 2008. To do this, he incorporated the cost impacts of inflation, productivity, and system growth. From the 2005-2007 average period to 2008, the U.S. Gross Domestic Product Price Index rose by 5.03%. AG/CUB states that during this same time, the number of customers for AIU increased by about 3%. AG/CUB asserts that these two components put upward pressure on costs of about 6 to 8%. AG/CUB contends that this cost pressure, however, would be partially offset by expected increases in productivity, a factor Mr. Fenrick's model takes into account in the parameter estimate of the trend variable.

AG/CUB says the change in cost performance is calculated as the difference between the actual percentage increase and the expected increase. AG/CUB states that these performance results are then compared with AIU's proposed statement of operating income, Ameren Exs. 2.1-2.3, and from this Mr. Fenrick determined the estimated inefficient O&M spending – that is, O&M spending AG/CUB believes is above what should be expected. Compared to the 2005-2007 spending, AG/CUB says AIU is proposing to increase D&CC spending by about 31% above the average level of AIU spending during 2005-2007. AIU's proposed A&G spending is about 24% above the average level of AIU spending during 2005-2007. AG/CUB avers that the model, however, estimates increases of only 6% in D&CC spending and 8% in A&G spending, based on an average performing utility. Taking into account expected cost increases, AG/CUB claims AIU's proposed costs are 25% more than an average performing utility for D&CC spending and 16% more for A&G spending.

AG/CUB states that to convert the cost performance into dollar terms, Mr. Fenrick estimated the percentage by which actual costs were above or below the expected amount. AG/CUB says he then used this number to approximate how much of AIU's proposed costs would need to change in order to achieve a given performance standard, whether that be an average or top quartile standard. For D&CC, AG/CUB contends that AIU's inefficiencies equate to $96.7 million for AIU's proposed 2008 test year spending levels, assuming an average performance standard. If a top quartile standard is used, AG/CUB asserts that D&CC inefficiencies amount to $132.3 million for AIU. AG/CUB claims that A&G expense inefficiencies are $61.8 million for AIU's proposed 2008 test year spending levels, assuming an average performance standard. Using a top quartile standard, AG/CUB asserts that A&G inefficiencies are estimated at $83.9 million. According to AG/CUB, in total, as measured against an average utility's performance, AIU's 2008 test year D&CC and A&G expenses are $158.5 million higher. As measured against the top quarter of utilities, AG/CUB alleges that AIU's sum of estimated D&CC and A&G inefficiencies is equal to $216.2 million.

AG/CUB states that Mr. Amen divided AIU's A&G expenses by the number of customers served and compared AIU cost per customer to a number of different peer groups. While Mr. Fenrick's model simultaneously accounts for multiple variables in determining expected costs, AG/CUB contends the AIU study depends solely on the construction of peer groups to adjust for the different operating conditions encountered by each sampled utility. Mr. Amen presents 16 separate peer groups, each one examining a variable similar to those used in Mr. Fenrick's study. Each AIU utility had its electric and gas delivery service operations compared both separately and together to a sample group for characteristics such as size, geographic location, ownership of generation, and combined gas and electric utilities as reported in 2007. AG/CUB complains that no single peer group encompassed all of these characteristics at one time.

AG/CUB says that while the peer group method is one that is frequently used in utility rate cases, it provides a less sophisticated analysis for the Commission to use. AG/CUB asserts that all of the suggested peer groups in the AIU study fail to adequately adjust for one or more variables that Mr. Fenrick‘s research found to be significant drivers of A&G spending. AG/CUB claims they are simple comparisons which do not address the impact of any one characteristic on any other characteristic, much less on AIU‘s operations as a whole. In AG/CUB's view, simplicity should not be held above accuracy. According to AG/CUB, the AIU study does not explicitly correct for scale economies inherent in A&G expenses as does Mr. Fenrick‘s. As size increases, it is expected that unit costs (A&G cost per customer) decrease due to economies of scale. AG/CUB alleges that if the analysis does not adequately adjust for this reality, it will be biased toward larger utilities. AG/CUB says that in most of the AIU peer groups, size is completely ignored. In two of the peer groups, AG/CUB says the impact of scale is acknowledged, but the analysts‘ inclusion criteria was wide ranging (100,000 to 1,000,000 customers), enough to significantly distort the results. AG/CUB contends that Mr. Amen‘s slides represent 16 different comparisons rather than one comprehensive comparison.

AG/CUB asserts that Mr. Amen also inappropriately includes A&G expenses without making any adjustments for the fact that AIU is not a vertically integrated utility. By including a large number of vertically integrated utilities in his sample, AG/CUB contends that Mr. Amen is biasing the results in favor of utilities that are not vertically integrated. According to AG/CUB, the A&G functions of a utility serve the production processes of a vertically integrated utility, if they exist. AG/CUB alleges that those utilities engaging in electricity production are putting forth more A&G ―effort” than their delivery-only counterparts, yet Mr. Amen‘s peer groups make no correction for this fact.

AIU witness Dr. Sosa claims that Mr. Fenrick‘s analysis should be ignored because it fails to include total sales as an output variable versus net generation in his A&G benchmarking model. AG/CUB states that Dr. Sosa ran his own analysis and concluded that with the correction of this ―flaw” his model yields results that are qualitatively similar to the results of Mr. Amen‘s peer group benchmark for A&G. In response to Dr. Sosa‘s criticism, Mr. Fenrick adjusted his model and ran his analysis again with the net generation output variable total sales. AG/CUB says the AIU results were both qualitatively and quantitatively similar to those found using the original econometric models. AG/CUB states that for estimated 2008 test year A&G expense inefficiencies were projected at over $50 million, versus the $61.8 million originally estimated, when compared to an average performance standard. AG/CUB says when compared to a top quartile performance standard, the levels are in excess of $70 million versus the $83.9 million from the original analysis.

AG/CUB contends that this shows the robustness of Mr. Fenrick‘s models and that the results are not dependent of model specifications, assuming these specifications account for the major drivers of cost. AG/CUB believes AIU failed to show such a model with results contrary to Mr. Fenrick. AG/CUB notes that Dr. Sosa was able to replicate Mr. Fenrick‘s model and results. According to AG/CUB, such replication from the opposing party offers the Commission additional confidence in the method and results undertaken by Mr. Fenrick in evaluating the reasonableness of AIU‘s proposed spending levels in this case.

c. LGI Position

According to LGI, Mr. Brodsky's testimony raises issues with AmerenIP's maintenance of its system. One of the areas that Mr. Brodsky examined was compliance with the NESC. Mr. Brodsky does not propose specific dollar amount adjustments for AmerenIP's efforts to resolve NESC violations, but he does express concern about the pace to remedy the violations. LGI, however, is still concerned with how the dollars are spent.

Mr. Brodsky found that since 2007 AIU has identified 34,262 NESC violations on the AmerenIP system and as of August 2009, 11% of the violations remain unresolved. LGI states that while AIU is periodically reporting the status of resolving the violations to Staff, Mr. Brodsky believes that AmerenIP should expedite the completion of the remediation since the unresolved NESC violations unnecessarily exposes the public to potential harm and could lead to failures in the electric system. LGI adds that Mr. Brodsky is an engineer and is familiar with the AmerenIP system. LGI indicates that he assisted Champaign and Urbana in conducting an audit of the AmerenIP system as part of a settlement agreement pertaining to the acquisition of IP by Ameren. LGI also claims he had a role in the development of the audit's requirements and had a role in formulating additional projects to improve reliability of AmerenIP's electric system serving Champaign and Urbana.

With regard to how maintenance dollars are spent for AmerenIP customers, LGI contends that AmerenIP's total investment per customer declined significantly between 2006 and 2009, falling form $143.82 per customer to $112.01 per customer. LGI believes that reductions in maintenance could lead to reductions in the reliability of electric service and that AmerenIP should increase its maintenance investments. LGI claims that the per customer maintenance and system improvement data is a more appropriate measurement for considering future reliability than other measurements such as CAIDI, SAIDI and CAIFI since those indices pertain to a given year. LGI suggests that when considering maintenance investments, one should also contemplate investments in the future. LGI asserts that the reliability data that AIU reports to the Commission indicates that the data was generally volatile and there was no clear pattern of improvement or degradation. When considering future reliability, LGI contends that quite often, it is likely to expect a lag period. LGI says that investments in the maintenance of a system today may cause improvement to reliability in the future, whereas looking at near term reliability indices only indicates what is happening or the consequences of investments that happened in the near past.

LGI claims it is more useful to look at maintenance investments on a per customer basis since the size of each of the three AIU electric systems is different. Between 2006 and 2009, LGI asserts that AmerenIP decreased its total annual maintenance investments from $70,646,100 to $24,910,400, an overall reduction of approximately 65%. On a per customer basis, LGI asserts AmerenIP decreased its maintenance investments from $114 per customer to $40 per customer, an overall reduction of approximately 65%. LGI states that maintenance investments for AmerenCILCO and AmerenCIPS increased in both the total dollars and per customer. Between 2006 and 2009, LGI claims AmerenCILCO's total investment per customer increased by 60% and AmerenCIPS' total investment per customer increased by 96%. LGI states that AmerenIP's total investment per customer decreased by 22% over the same period. LGI is concerned about the trend. LGI recommends that the Commission monitor AmerenIP's annual maintenance investments and system improvement investments and investigate why AmerenIP's investments are lagging that of AmerenCILCO and AmerenCIPS.

d. Commission Conclusion

AIU performed certain benchmarking studies that it claims demonstrate that its O&M expenses are reasonable. AG/CUB contends that AIU's studies are flawed. AG/CUB also presented an econometric study which it claims demonstrates that AIU's costs are higher than should be expected. AIU believes that AG/CUB's study is flawed. In addition, LGI expresses concern that AIU is not expending enough money in maintaining the AmerenIP distribution system. AIU disputes LGI's assertions and objects to the recommendations that additional monitoring and reporting is necessary with regard to the reliability of its distribution system.

There are essentially two experts that analyzed the same data, but utilized different approaches, and reached opposite conclusions. The Commission finds that the studies presented by Mr. Amen, while not perfect, are straightforward and easy to understand. In the Commission's view, the study presented by Mr. Fenrick is obviously more complex and therefore more prone to error and improper interpretation. The Commission believes it is particularly important to take care when attempting to use an econometric model to either predict outcomes or draw conclusions about causes and effects. In this instance, the Commission is not convinced that the AG/CUB's study demonstrates what it contends that it does. Even if one were to assume that it did demonstrate that AIU is inefficient and that some of its costs are higher than they should be, AG/CUB has provided no real method whereby the results could be used. In other words, AG/CUB has not shown what costs, if any, should be reduced or eliminated from AIU's operating expenses. The Commission believes there would be no way to utilize the AG/CUB study for ratemaking purposes in this proceeding, even if the Commission were fully convinced of its validity.

The Commission and its Staff have been monitoring and will continue to monitor AIU's activities to operate and maintain the distribution system of AmerenIP. However, the Commission shares LGI's concerns. As discussed elsewhere in this Order, the Commission has required AIU to correct its NESC violations by the end of 2013. The Commission concludes that the specific recommendations of LGI regarding monitory and reporting are reasonable and those recommendations are hereby accepted.

VI. COST OF CAPITAL/RATE OF RETURN

A. Overview

A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type of capital affects the overall or weighted average cost of capital, which is the ROR a utility is authorized to earn on its net original cost rate base.

The Commission relies on the cost of capital standard to determine a fair ROR. This cost, which can be determined from the overall ROR or weighted average cost of capital, should produce sufficient earnings and cash flow when applied to the respective company's rate base at book value to enable a company to maintain the financial integrity of its existing invested capital, maintain its creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable a company to continue to meet the needs of its customers.

These standards are effectively mandated by the landmark U.S. Supreme Court decisions Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944) ("Hope"). Meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holders and equity holders, alike.

B. Capital Structure

1. AmerenCILCO

According to AmerenCILCO, its March 31, 2009, preferred stock balance is $18,893,567. This number reflects the carrying value or net proceeds amount of AmerenCILCO's preferred stock as found in the embedded cost calculation for this component of capitalization. Staff adjusted the discount expense for AmerenCILCO's outstanding preferred stock issues, which Staff maintains had a small effect on the balance and did not affect the embedded cost of preferred. As a result, Staff's adjusted balance for AmerenCILCO's preferred stock is $18,893,282. AmerenCILCO and Staff both indicate they are of the opinion this represents an immaterial difference.

As the parties are in agreement that there is no material difference in the result whether AmerenCILCO's suggested preferred stock balance or Staff's suggested balance is used, the Commission will adopt Staff's suggested preferred stock balance of $18,893,282.

AmerenCILCO maintains that the balance of AmerenCILCO's short-term debt equals $32,017,993. Staff does not take issue with AmerenCILCO's calculation of the balance of short-term debt. The Commission finds the calculation of short-term debt to be reasonable and it will be adopted.

With respect to AmerenCILCO's long-term debt, Mr. O'Bryan testified that the balance, $271,492,364, is the total carrying value of all of AmerenCILCO's long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds method, as outlined in AmerenCILCO Ex. 13.2. Staff witness Phipps testified that in her opinion, this balance should be $271,691,990. AmerenCILCO and Staff both indicate that they are of the opinion that this adjustment represents an immaterial difference. As the parties are in agreement that there is no material difference in the result whether AmerenCILCO's suggested long-term debt balance or Staff's suggested balance is used, the Commission will adopt Staff's suggested long-term debt balance of $271,691,990.

AmerenCILCO and Staff agree that AmerenCILCO's March 31, 2009, common equity balance is $249,457,171. The Commission finds the common stock balance for AmerenCILCO to be reasonable and it will be adopted.

2. AmerenCIPS

AmerenCIPS and Staff agree that AmerenCIPS' balance of preferred stock is $48,974,984, which is the carrying value or net proceeds amount of AmerenCIPS' preferred stock as found in the embedded cost calculation for this component of capitalization. The Commission finds the agreed preferred stock balance for AmerenCIPS to be reasonable and it will be adopted.

AmerenCIPS maintains, and Staff does not dispute, that AmerenCIPS' short-term debt balance equals $58,098,936. The Commission finds AmerenCIPS' proposed short-term debt balance to be reasonable and it will be adopted.

AmerenCIPS initially proposed a balance of long-term debt of $397,043,827, which AmerenCIPS states is the total carrying value of all of its long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds method. Staff argues that AmerenCIPS' balance of long-term debt should be $397,751,866, which reflects an adjustment to remove any incremental cost increase due to AmerenCIPS' decision to refinance a $67 million, 5-year intercompany promissory note bearing an interest rate of 4.7% with $61.5 million in 30-year bonds bearing an interest rate of 6.7%. While AmerenCIPS argued in its previous rate case, Docket Nos. 07-0585 et al. (Cons.), that AmerenCIPS was justified in refinancing the 4.70% note; AmerenCIPS accepts Staff's position on this issue for the purposes of this case only. The

Commission finds that Staff's proposed balance of long-term debt for AmerenCIPS is reasonable, and it will be adopted.

AmerenCIPS proposes a December 31, 2008, common equity balance of $478,676,606. Staff agrees with AmerenCIPS' proposed common equity balance. The Commission finds AmerenCIPS' proposed common equity balance to be reasonable and it will be adopted.

3. AmerenIP

a. Preferred Stock Balance

AmerenIP and Staff agree that AmerenIP's balance of preferred stock is $45,786,945, which is the carrying value or net proceeds amount of AmerenIP's preferred stock as found in the embedded cost calculation for this component of capitalization. The Commission finds the proposed preferred stock balance for AmerenIP to be reasonable and it will be adopted.

b. Short-Term Debt Balance

(1) AmerenIP Position

AmerenIP maintains that its balance of short-term debt is $10,404,002, while noting that Staff argues that AmerenIP's short-term balance should be adjusted to $10,791,502 to reflect an adjustment wherein the short-term debt calculation does not subtract cash from short-term debt. According to AmerenIP, Staff argues that for the one month during the short-term debt measurement period that AmerenIP had short-term debt outstanding, AmerenIP subtracted —excess cash" from short-term debt. AmerenIP argues that Staff admits that AmerenIP's calculation does not affect AmerenIP's overall cost of capital, arguing, however, that the calculation was improper because it is not a part of short-term indebtedness.

AmerenIP submits that its short-term debt balance was calculated pursuant to the formula set forth in the "Illinois Commerce Commission Rate of Return Instructions, Section 285.4020 Schedule D-2: Cost of Short-term Debt (b-4)" (as outlined in AmerenIP Ex. 13.3). AmerenIP argues that it followed the Commission's approach from recent rate proceedings, which calculates the amount of short-term debt in the capital structure by taking an average of month-end short-term debt balances six months prior to and following the capital structure measurement date. This approach aligns the measurement period with a midpoint that coincides with the measurement date of the long-term capital structure components.

(2) Staff Position

Staff takes the position that AmerenIP's calculation improperly subtracts ―excess cash" from the short-term debt balance. Staff explains that the short-term debt calculation adopted by the Commission in AmerenIP's 2007 rate case, which subtracted ―excess cash" from short-term debt, was based on very specific, unique circumstances that do not apply in the instant case. Staff, therefore, does not subtract cash from short-term debt in its calculations. Staff notes, however, that notwithstanding Staff's opposition to AmerenIP's improper short-term debt balance calculation, AmerenIP's improper calculation does not materially affect AmerenIP's overall cost of capital.

(3) Commission Conclusion

The Commission notes that AmerenIP indicates it is attempting to follow the Commission decision from AIU's last rate case, Docket Nos. 07-0585 et al. (Cons.) by subtracting "excess" cash from short-term debt balances, while Staff argues that decision was based on the unique circumstances presented which are not present in this proceeding. The Commission agrees with Staff that the circumstances present in the prior rate proceeding which caused AIU to retain "excess" cash are not present in this proceeding, and the Commission will therefore adopt Staff's proposed short-term debt balance for AmerenIP. The Commission also recognizes that the parties agree that opting for Staff's suggestion over that of AmerenIP will not have a material impact on AmerenIP's overall cost of capital.

c. Long-Term Debt Balance

(1) AmerenIP Position

AmerenIP maintains that its balance of long-term debt is $1,357,044,075, which is the total carrying value of all of the Company's long-term debt (first mortgage bonds and pollution control bonds) using the net proceeds methods, while Staff argues that AmerenIP's long-term debt balance should equal $1,307,983,675, to reflect a reduction in the principal amount of AmerenIP's October 2008 debt issuance from $400 million to $350 million.

AmerenIP opines that Staff's adjustment to exclude a portion of the principal amount of AmerenIP's long-term debt issuance is unwarranted. AmerenIP notes that its long-term debt issuance was not impacted by its temporary short-term debt with an objective of maintaining an appropriate level of available liquidity. AmerenIP avers it sized the debt issuance to retire its own short-term debt with an objective of maintaining an appropriate level of available liquidity. AmerenIP notes that prior to its recent ratings upgrade, it had sub-investment grade, or ―junk" issuer credit ratings which made it subject to material cash collateral calls from its counterparty suppliers. AmerenIP argues that these collateral demands can create sizable, volatile, unpredictable and immediate needs for cash, thus requiring meaningful liquidity resources. AmerenIP further argues that these obligations must be met regardless of the timing and amount of the company's incoming cash flows. AmerenIP avers that at the time of the issuance, the money pool loan to AmerenCIPS was simply a temporary use of funds which would have otherwise been maintained as highly liquid short-term investment as a liquidity reserve.

AmerenIP notes at the time of this debt financing, AmerenIP was fully utilizing its capacity under its two bank facilities and had to further meet its short-term borrowing requirements through borrowings from Ameren. AmerenIP argues that another key factor impacting the need for this financing and the requirement to improve AmerenIP's liquidity position was the condition of the capital markets and bank markets, noting that during this time, the capital markets were in a high state of distress and the bank markets were effectively closed. AmerenIP states that after filing bankruptcy, Lehman Brothers was no longer funding loan requests under these facilities, and at the time of its filing, Lehman Brothers represented $71 million of the $1 billion in credit facilities AmerenIP could directly access, while three other troubled institutions represented a combined total of approximately $265 million under these facilities. AmerenIP notes that Staff witness Phipps acknowledged these circumstances existed in the financial market at the time.

AmerenIP claims that the evidence showed the debt capital markets were also severely distressed, as many issuers could not access debt capital, and those that could were faced with very high investor return requirements as evidenced by higher credit spreads. AmerenIP avers that as AIU's bank facilities were scheduled to expire in January 2010, and with no assurance that the bank markets would improve and permit the extension or renewal of these facilities, AmerenIP took the prudent step of completing a refinancing in order to improve its liquidity position and ensure that it would have sufficient liquidity to fund its utility operations going forward.

AmerenIP notes that Staff alleges that AmerenIP could have recalled its money pool loan to AmerenCIPS, in which case AmerenCIPS could have borrowed its funds from Ameren. AmerenIP disputes Staff's argument that if AmerenIP had recalled its money pool loan, it would not have needed to borrow $60 million from Ameren on October 21, 2008, and that if AmerenIP had not borrowed from Ameren on October 21, 2008, it could have reduced the size of its October 2008 long-term debt issue from $400 million to $350 million because it would have had less short-term debt to retire.

While Staff avers that Ameren and its subsidiaries, including AIU, did not believe the potential reductions in available capacity under the credit facilities would materially affect their liquidity if Lehman Brothers did not fund its commitments and that AmerenIP did not require the additional $50 million long-term debt balance to repay existing short-term indebtedness; AmerenIP opines that Staff's arguments utilize the benefit of hindsight and can only be made now given conditions in the capital and bank markets have improved. AmerenIP notes that it would have had to continue to fund itself regardless of whether it had been able to access the capital markets in June 2009 to fund its long-term debt maturity, without having received an upgrade in its credit ratings, and regardless of the direction of commodity prices and resultant demands for collateral pricing. AmerenIP argues it was concerned about renewal one year in advance because by the time Ameren IP completed its $400 million long-term debt financing in October 2008, Moody's Investors Service ("Moody's") had already been publicly signaling its focus on the renewal of AmerenIP's, as well as AmerenCILCO's and AmerenCIPS', bank facilities, noting this in August, and September, 2008 credit reports.

(2) Staff Position

Staff recommends that the Commission determine that AmerenIP's March 31, 2009, long-term debt balance was $1,307,983,675, while AmerenIP recommends a balance of $1,357,044,075. Staff states it adjusted the principal amount of AmerenIP's 9.75% senior secured notes by calculating the amount of net proceeds that would be required to repay AmerenIP's $343.7 million borrowings under the 2006 and 2007 credit facilities, taking into consideration AmerenIP's $1.2 million debt expense, 1.58% original issue discount, and 70 basis points underwriting fee. Staff calculated that AmerenIP would have needed to issue $350 million in debt to raise sufficient cash to retire $343.7 million in short-term borrowings and, therefore, proposes to reduce the principal amount of AmerenIP's October 2008 debt issuance to $350 million from $400 million.

Staff notes that on October 23, 2008, AmerenIP issued $400 million, 9.75% senior secured notes, and used the proceeds to repay borrowings under the bank facilities and the money pool. AmerenIP asserts that it issued indebtedness totaling $400 million instead of a lower amount because this was the amount of AmerenIP's outstanding short-term debt at the time of the issuance. Staff notes that on October 22, 2008, AmerenIP was simultaneously contributing surplus funds to and borrowing from the money pool. Staff argues that such transactions are unnecessary given the Commission's rules governing money pools require that money pool borrowers repay the principal amount of money pool loans on demand of the lending utility. Staff opines that AmerenIP should have recalled its money pool loan and issued long-term debt in an amount sufficient to repay its credit facility borrowing rather than issue $400 million in bonds, given the high cost of long-term debt at that time. Staff argues that without its proposed adjustment, AmerenIP customers would pay a 9.75% interest rate on $50 million in bonds, the proceeds from which AmerenIP did not require for its electric and gas delivery services operations.

Staff states that AmerenIP argues that it did not recall its money pool loans in order to reduce the amount of the $400 million bond issuance, as AmerenIP was holding cash and could temporarily provide AmerenCIPS with the cash it needed. Staff opines that AmerenIP's argument supports Staff's position that AmerenIP had liquidity available with which it could reduce its outstanding short-term debt before AmerenIP went to market securities in a high cost debt market.

Staff avers that while AmerenIP argues it did not need the funds it loaned to AmerenCIPS during October 2008, AmerenIP further states that it was fully utilizing its capacity under its two bank facilities and had to further meet its short-term borrowing requirements through borrowings from Ameren. Staff argues that these two statements are contradictory, as a utility that has cash available to lend should not simultaneously need to borrow additional short-term funds from either banks or affiliates. Staff opines that AmerenIP could have recalled its money pool loan to AmerenCIPS, in which case AmerenCIPS could have borrowed funds from Ameren or from the credit facility. Instead, Staff argues, AmerenIP borrowed $60 million from Ameren on October 21, 2008, which AmerenIP repaid two days later. Staff avers that if AmerenIP had not borrowed from Ameren on October 21, 2008, it could have reduced the size of its October 2008 long-term debt issue from $400 million to $350 million. Furthermore, Staff notes that AmerenIP‘s cash balance grew significantly from October 20, 2008 to October 22, 2008, indicating that AmerenIP did not use the proceeds from the Ameren loan.

Staff avers that on October 20, 2008, AmerenCIPS' short-term debt balance was less than AmerenIP's, as AmerenCIPS had borrowed $64 million from the money pool, had no outstanding bank loans, surplus funds or cash, leaving AmerenCIPS with $135 million in total available liquidity. Nevertheless, Staff argues that AmerenIP issued $50 million more long-term debt than required for AmerenIP‘s utility operations while AmerenCIPS relied upon low cost money pool funds rather than issue any long-term debt during 2008.

Staff disagrees with AmerenIP's position that it needed substantial cash balances, as it does not have ongoing cost-effective daily access to same-day funds for uncertain working capital needs due to the three-day lag between when it requests a London Inter-Bank Offer Rate ("LIBOR") loan and when the banks fund the LIBOR loan, and that AmerenIP also commonly holds cash to fund payment requirements on a daily basis and to be ready to fund cash collateral requirements, which can change on a daily basis.

Staff notes that the three-day lag on LIBOR loans has been a requirement since AIU entered the 2006 credit facility. Furthermore, Staff avers that the pricing schedule for the AIU credit facility mirrors the pricing schedule for Ameren‘s non-utility credit facility, including an —ABR spread” that applies to same-day loans. Staff notes the ABR rate would have to be 673 basis points higher than current cost of short-term bank loans for AIU (3.02%) before it would be as costly as AmerenIP‘s 9.75% bonds. Staff submits that over the long-term, the ABR rate would be less costly than AmerenIP‘s 10-year bonds because borrowers may prepay ABR loans without premium or penalty, while AmerenIP locked in the 9.75% rate for 10 years.

Staff argues that AmerenIP never explains why its working capital and cash collateral requirements are not predictable, presenting no evidence that it is unaware of upcoming due dates for the services and goods it purchases such that substantial calls for cash payments can occur on fewer than three days‘ notice. Staff submits that the record contains evidence that there are no significant surprise calls for cash, as none of the contractual obligations for which AmerenIP received three days or less notice during October 2008 was larger than $5 million. Further, Staff opines that there was little risk of significant surprise calls for cash, as AIU allowed AmerenCIPS to carry less than $1 million cash balances (including contributions to the money pool) from October 17, 2008 through March 31, 2009.

Although AmerenIP claims it needed to issue excess high cost long-term debt due to the financial crisis, claiming that net available liquidity to AIU was as low as $99 million in September, causing AmerenIP to conservatively and proactively manage its own liquidity, Staff finds these arguments to be flawed.

Staff opines that the reference to the $99 million liquidity available to AIU under the credit facilities on September 25, 2008, ignores AIU‘s adequate aggregate cash balance. Staff further submits that this argument ignores the fact that of the three utilities, only one issued excess debt at high cost. Staff notes that on September 18, 2008, AIU had available liquidity (including cash balances) of approximately $1.197 billion, excluding the $121 million of Lehman Brothers‘ credit facilities commitments.

While AmerenIP argues that AIU's bank facilities were scheduled to expire in January 2010 with no assurance that the bank markets would improve and permit the extension or renewal of these facilities, Staff submits that AmerenIP issued the long-term indebtedness more than one year before AIU's bank facilities would expire.

Staff avers that none of AmerenIP‘s reasons for maintaining substantial cash balances warrants AmerenIP customers paying 9.75% interest on $50 million in bonds for ten years, the proceeds from which earned a return below 0.25% through either a loan to an affiliate or an investment in money market funds.

(3) Commission Conclusion

The Commission notes that Staff recommends a long-term debt balance for AmerenIP of $1,307,983,675; approximately $50 million less than that recommended by AmerenIP, to reflect what Staff believes was excessive borrowing by AmerenIP to repay borrowing under bank facilities and the money pool. AmerenIP argues it was necessary to borrow $400 million because this was the amount of short-term debt outstanding at the time of the long-term borrowing.

It appears to the Commission that AmerenIP issued more long-term debt than required for AmerenIP's utility operations, 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's proposed long-term debt balance for AmerenIP for the purposes of this proceeding.

d. Common Equity Balance

(1) AmerenIP Position

AmerenIP proposes a March 31, 2009, balance of common equity of $1,110,636,039, adjusted for purchase accounting, ratemaking, and other non-cash items, while Staff maintains that AmerenIP's balance of common equity should be $1,052,637,039 to reflect an adjustment removing the $58 million common equity infusion by Ameren during March 2009.

AmerenIP disputes Staff's exclusion of the equity infusion from AmerenIP's capital structure, arguing that ignoring the credit and liquidity enhancing step of making a common equity infusion into AmerenIP implies neither of these objectives is worthwhile. AmerenIP argues that Ameren infused $58 million of common equity into AmerenIP in an effort to bolster AmerenIP's credit quality by enhancing its credit metrics and de-levering its capital structure, which action was intended to send a positive signal to the rating agencies and fixed income investors regarding the importance of AmerenIP's credit quality. AmerenIP submits that this was another of the multiple credit enhancing steps taken by Ameren and AmerenIP which ultimately led to improvement in AmerenIP's ratings including the restoration of its issuer rating to investment grade. AmerenIP opines that this equity infusion, as well as an additional equity infusion made in September 2009, further enhances AmerenIP's ability to achieve its stated equity ratio target in the range of 50% to 55%.

AmerenIP notes that although the March equity infusion resulted in a temporary increase in cash, this enhanced AmerenIP's liquidity position and reduced the extent to which it would need to rely on its bank facilities. AmerenIP argues that at the time, AmerenIP's bank facilities had not yet been renewed and its ability to do so was uncertain. AmerenIP notes that while the capital markets also were tentative and AmerenIP was facing a near-term $250 million long-term debt maturity, once it became apparent that AmerenIP would be able to successfully complete the renewal of its bank facilities, it elected to fund this long-term debt with cash.

While Staff acknowledges that AmerenIP's objectives were worthwhile, Staff maintains that Moody's August 13, 2009, announcement of AIU's upgrade does not support AmerenIP's contention that the common equity infusion ultimately led to Moody's decision to restore AmerenIP's credit rating to investment grade. Staff also argues that AmerenIP did not require an equity infusion from Ameren due to a lack of available liquidity because AmerenIP had available liquidity of at least $461 million to $590 million during March 2009.

AmerenIP acknowledges that Moody's did not specifically cite the $58 million common equity infusion in its August 13, 2009, announcement of the ratings upgrade for AmerenIP. However, AmerenIP argues that Moody's was clearly aware of this equity infusion and plans for further equity infusions and would have incorporated that into its analysis leading to the upgrade, noting an AmerenIP-specific credit opinion published by Moody's the day following the announcement of the upgrade wherein Moody's cited concerns around additional pressure on AmerenIP's financial metrics as a potential driver or factor which could drive the rating down. AmerenIP avers that common equity infusions are helpful for financial metrics and would thus act as an offset to any factor placing negative pressure on these metrics.

(2) Staff Position

For ratemaking purposes, Staff recommends AmerenIP's March 31, 2009, common equity balance equals $1,052,636,039. Staff recommends removing from AmerenIP's common equity balance a $58 million common equity infusion by Ameren that occurred during March 2009 in order to bolster AmerenIP's equity ratio. Staff argues that this equity infusion bolstered AmerenIP's equity ratio after AmerenIP issued $50 million more bonds than necessary to repay its outstanding short-term bank loans. Staff therefore recommends removing both the $50 million in long-term debt that AmerenIP did not require and the subsequent $58 million equity infusion.

Staff contends that if AmerenIP had issued $350 million 9.75% bonds during October 2008 instead of $400 million, then bolstering AmerenIP's common equity ratio would not have been necessary. While AmerenIP alleges the common equity infusion was a credit enhancing action taken by Ameren and AmerenIP that ultimately led to Moody's decision to restore AmerenIP's credit rating to investment grade, Staff opines that Moody's August 13, 2009, ratings upgrade announcement does not support AmerenIP's claim, instead stating that the upgrade of AIU was prompted by the recent execution of new bank facilities and the improved political and regulatory environment for utilities in Illinois.

Despite AmerenIP's claim that the equity infusion enhanced AmerenIP's liquidity position and reduced the extent to which it would need to rely on its bank facilities, Staff counters that AmerenIP did not need the cash from the $58 million infusion of common equity, noting that AmerenIP's March 2009 surplus funds balances were significant. Staff further avers that since the October 2008 bond issuance, AmerenIP has not borrowed under any of its $350 million bank credit facilities or the money pool. Staff opines that this shows that during March 2009, AmerenIP had sufficient available liquidity. Therefore, Staff urges the Commission to reject AmerenIP's proposed common equity balance and instead adopt Staff's proposed common equity balance.

(3) Commission Conclusion

The Commission agrees with Staff that the $58 million equity infusion from Ameren should be removed from AmerenIP's common equity balance. The record does not appear to contain any real justification for the equity infusion, other than the fact that AmerenIP borrowed $50 million more than required in its March 2009 bond issue, which the Commission has already determined should be removed from AmerenIP's long-term debt balance. As the Commission has made that determination regarding AmerenIP's long-term debt balance, it is clear the equity infusion should likewise be removed from the common equity balance. This adjustment will ensure that ratepayers will not be burdened with a capital structure that includes an excessive amount of common equity.

e. Staff's Alternative AmerenIP Capital Structure

AmerenIP notes that in the event the Commission accepts Staff's adjustment to AmerenIP's long-term debt balance, but does not adopt Staff's recommended adjustment to AmerenIP's common equity balance, then Staff recommends that the Commission also not remove the $50 million in debt AmerenIP issued in October 2008 from AmerenIP's long-term debt balance. As an alternative, Staff recommends the Commission adjust the interest rate on that $50 million in debt to the embedded cost of long-term debt had the $50 million in debt not been issued, or 7.83%. Staff maintains that, absent such an adjustment, AmerenIP's before-tax ROR on rate base would be higher if the Commission only reduced the balance of the October 2008 debt issue, than if the Commission adjusted neither the amount of the October 2008 debt issue nor the March 2009 common equity infusion.

Staff recommends the Commission consider the related adjustments to AmerenIP's long-term debt and common equity balances together. In terms of capitalization, the March 2009 $58 million common equity infusion essentially offsets the $50 million in excess debt IP issued in October 2008. Staff argues that if AmerenIP had issued $50 million less in debt in October 2008, it would not have needed $58 million of common equity in March 2009 to keep its common equity ratio from sinking further. Nevertheless, if the Commission agrees with Staff's adjustment to AmerenIP's long-term debt balance, but not the adjustment to AmerenIP's common equity balance, then Staff recommends the Commission also not remove from AmerenIP's long-term debt balance the $50 million in excess debt IP issued in October 2008.

Staff's alternative recommendation is to adjust the interest rate on the $50 million in excess debt to 7.83%, which Staff submits is AmerenIP's embedded cost of long-term debt had the $50 million in excess debt never been issued. Staff submits this approach would prevent the $50 million of excess debt from increasing AmerenIP's embedded cost of long-term debt while still recognizing the equity infusion. Staff notes the before tax cost of common equity is more expensive than even 9.75% debt. Staff submits that absent Staff's alternative proposal, AmerenIP's before-tax ROR on rate base would be higher if the Commission only reduced the balance of the October 2008 debt issue than if the Commission adjusted neither the amount of the October 2008 debt issue nor the March 2009 common equity infusion.

The Commission notes that since this order accepts both Staff's recommendation to reduce AmerenIP's long-term debt balance, as well as to reduce AmerenIP's common equity balance, there is no need to address this issue.

C. Cost of Preferred Stock

Staff and AIU agree that AmerenCILCO's March 31, 2009, embedded cost of preferred stock equals 4.61%; AmerenCIPS' December 31, 2008, embedded cost of preferred stock equals 5.13%; and AmerenIP's March 31, 2009, embedded cost of preferred stock equals 5.01%. The Commission finds these costs of preferred stock to be reasonable for each company, and they will be adopted for the purposes of this proceeding.

D. Cost of Long-Term Debt

1. AmerenCILCO

a. AmerenCILCO Position

AmerenCILCO proposes an embedded cost of long-term debt of 8.161% as of March 31, 2009, noting however that Staff seeks to adjust the coupon rate for AmerenCILCO's 8.875% bonds to reflect AmerenCILCO's alleged higher business risk profile due to its non-utility affiliates. Staff maintains that, during December 2008, AmerenCILCO's issuer rating from Moody's was Ba1 and its senior secured debt rating was Baa2. Staff acknowledges that Moody's classifies AmerenCILCO as having a —Medium" business risk, however, Staff maintains Moody's views U.S. transmission and distribution utilities' business risk as —Low." AmerenCILCO avers Ms. Phipps evaluated Moody's rating factors for AmerenCILCO using the benchmarks for low business risk electric utilities, and concluded that AmerenCILCO's implied issuer rating would be Baa1 for its regulated utility operations. Ms. Phipps argues that, since AmerenCILCO's secured debt rating is two notches above its unsecured ratings, Moody's would assign AmerenCILCO a secured debt rating of A2 if non-utility affiliates had not increased its business risk. Ms. Phipps makes a similar argument with respect to the Standard & Poor's ("S&P") rating, arguing that since AmerenCILCO's current S&P secured debt rating is two notches above its issuer rating, S&P would assign AmerenCILCO a secured debt rating of A if its business risk profile was not affected by its riskier non-utility affiliates.

AmerenCILCO states Ms. Phipps also changed various dates to conform to AmerenCILCO's 2008 Form 21 annual report and set the annual amortization of expense, premium, or discount, and loss or gain for each debt issue using a rate that she purports recovers those debt costs in equal monthly amounts between the embedded cost of debt measurement date and the end of the applicable amortization period. AmerenCILCO notes Ms. Phipps also argues for removal of three months of amortization from the year-end 2008 unamortized balances of expense, premium or discount, and loss or gain for each debt issue to determine the unamortized balances on the March 31, 2009, measurement date.

AmerenCILCO opines the rating agencies use a combination of qualitative factors along with quantitative analysis in determining an issuer's credit ratings, and are ultimately the final arbiters of credit ratings, and any adjustment based on an assumption that AmerenCILCO would be entitled to a higher rating is unfounded. AIU submits Ms. Phipps does not offer any compelling evidence that AmerenCILCO's rating, or the coupon/interest rate on AmerenCILCO's 2008 long-term debt issuance would have been any different than what either was at the time this debt was issued. AmerenCILCO states it needed to complete this refinancing in order to reduce borrowings under its bank facilities (its borrowing sublimits thereunder were fully utilized at the time) and improve its liquidity position. AmerenCILCO avers that to deprive it of its ability to adequately recover the cost of this capital in effect is penalizing AmerenCILCO for taking a prudent action to protect its ability to maintain appropriate levels of liquidity and ensure a reliable, continuing ability to make payments, including the posting of collateral, to its suppliers, employees, etc. on a contractual and timely basis going forward.

While Staff indicates it does not address whether AmerenCILCO should have issued the long-term debt, Staff continues to argue that AmerenCILCO is affected by its non-utility affiliates. AmerenCILCO suggests that it is inappropriate for Staff to step into the shoes of the ratings agencies and opine that the credit ratings for AmerenCILCO would be any different than they are today if it no longer had an unregulated generation subsidiary and/or was no longer owned by an intermediate parent company.

b. Staff Position

Staff proposes an embedded cost of long-term debt for AmerenCILCO of 6.69%, as opposed to AmerenCILCO's proposed rate of 8.16%. Staff proposes to adjust the coupon rate for AmerenCILCO's 8.875% bonds to reflect the low business risk profile of AmerenCILCO's electric and gas delivery service operations. Staff notes that Moody's, S&P and Fitch Ratings ("Fitch") each recognize that non-utility affiliates affect CILCO's credit rating.

Staff argues that despite the rating agencies' comments that AmerenCILCO's affiliation with CILCORP and Ameren Energy Resources Generating Co. ("AERG") increase AmerenCILCO's business risk, AmerenCILCO has not performed any analyses regarding the effect of AmerenCILCO's affiliation with CILCORP and AERG on the 8.875% coupon rate for AmerenCILCO's December 2008 bond issuance. Staff, therefore, proposes to remove the incremental risk in AmerenCILCO's credit ratings resulting from its non-utility affiliates.

Regarding Moody's ratings, Ms. Phipps considered that during December 2008, AmerenCILCO's issuer rating from Moody's was Ba1 and its senior secured debt rating was Baa2, with Moody's classifying AmerenCILCO as having ―Medium" business risk, which is typical for integrated utilities. Ms. Phipps states that Moody's viewed U.S. transmission and distribution utilities' business risk as ―Low." Ms. Phipps then evaluated Moody's rating factors for AmerenCILCO using the benchmarks for low business risk electric utilities, concluding that AmerenCILCO's implied issuer rating would be Baa1 for its regulated utility operations. Since AmerenCILCO's secured debt rating is two notches above its unsecured ratings, Ms. Phipps concluded that Moody's would assign AmerenCILCO a secured debt rating of A2 if non-utility affiliates had not increased its business risk.

Regarding S&P ratings, Ms. Phipps evaluated AmerenCILCO's implied stand-alone S&P credit rating using financial ratios published by S&P, combined with a —Strong" business risk profile rather than AmerenCILCO's actual business risk profile of —Satisfactory." Ms. Phipps stated that the S&P Business Risk/Financial Risk Matrix (—S&P rating matrix") indicates AmerenCILCO's current BBB issuer rating is consistent with a —Satisfactory" business risk profile and AmerenCILCO's stand-alone financial ratios, as calculated by S&P. Using the S&P rating matrix, Ms. Phipps concluded that changing AmerenCILCO's business risk profile to —Strong," would likely raise its issuer rating to BBB+. Since AmerenCILCO's current S&P secured debt rating is two notches above its issuer rating, Ms. Phipps estimates S&P would assign AmerenCILCO a secured debt rating of A if its business risk profile was not affected by its riskier non-utility affiliates.

Using AmerenCILCO's implied, low business risk, senior secured ratings of A2/A, Ms. Phipps estimated a coupon rate for AmerenCILCO's December 2008 bonds. Ms. Phipps states she reviewed A-rated, secured, electric utility debt financings with five-year terms to maturity that occurred between September 25 and December 31, 2008, and at that time, five-year, A-rated secured electric utility bonds were yielding 6.24%.

Ms. Phipps avers that despite AmerenCILCO's claim that it needed to complete this refinancing in order to reduce borrowings and improve its liquidity position; she did not argue that AmerenCILCO should not have issued $150 million long-term indebtedness. Ms. Phipps argues that her adjustment is limited to removing any incremental cost of AmerenCILCO's capital due to its non-utility affiliates, as required by Section 9-230 of the Act.

While AmerenCILCO claims that Staff does not present any compelling evidence regarding whether AmerenCILCO's rating, or the rate on its debt offering, would have been any different than what either was at the time this debt was issued, Staff argues that AmerenCILCO's decision to purchase the credit rating services of S&P, Moody's, and Fitch belies its contention that the opinions of those credit ratings agencies do not constitute compelling evidence. Staff notes that each of the rating agencies notes that AmerenCILCO's non-utility affiliates affect its credit rating. Staff notes that S&P ratings indicate that AmerenIP's strong business profile reflects its lower operating risk, being a distributor with no owned generation, therefore AmerenIP has less operating risk than a fully integrated utility. Staff contrasts this with AmerenCILCO, wherein S&P states that AmerenCILCO's satisfactory business profile reflects its non-regulated businesses, partially offset by its lower risk regulated transmission and distribution business.

While AIU argues actual ratings could span one notch above or below the midpoint indicated on the S&P rating matrix, meaning AmerenCILCO's rating using a —Strong" business risk profile could still be BBB (actual rating), rather than BBB+

(adjusted rating), Staff notes the first step in making Ms. Phipps' adjustment to AmerenCILCO's S&P rating was plotting the actual S&P issuer rating on the matrix using the —Significant" financial risk profile and the —Satisfactory" business risk profile that S&P actually assigns AmerenCILCO. Staff states that without changing where AmerenCILCO's rating falls on the financial risk spectrum, Ms. Phipps moved AmerenCILCO's business risk profile up one category to —Strong," thereby changing only the business risk profile; everything else remaining the same.

Staff states that Moody's, S&P, and Fitch have never stated their review of AmerenCILCO's financial performance is indicative of the stand-alone, regulated utility, without the presence of any unregulated subsidiaries. Staff notes that the August 14, 2009, Moody's report notes that CILCORP's debt and AERG's non-utility operations affect AmerenCILCO's credit rating. Staff asserts it is not clear why the rating agencies would view AmerenCILCO as a stand-alone regulated utility since AIU is not certain when AmerenCILCO would spin-off AERG. For all the foregoing reasons, Staff believes its recommended costs of AmerenCILCO's long-term debt for ratemaking purposes should be adopted.

c. Commission Conclusion

It appears to the Commission that Staff is of the opinion that the presence of the unregulated affiliates of AmerenCILCO is raising the cost of AmerenCILCO's long-term debt, which Staff argues is contrary to Section 9-230 of the Act, which states as follows:

> In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any (i) incremental risk, (ii) increased cost of capital, or (iii) after May 31, 2003, revenue or expense attributed to telephone directory operations, which is the direct or indirect result of the public utility's affiliation with unregulated or nonutility companies.

The Commission notes that this issue of increased risk from an unregulated affiliate has been addressed previously by the courts, including Illinois Bell Telephone Co. vs. Illinois Commerce Comm'n., 218 Ill. Dec. 598, 283 Ill. App. 3d 188, 669 N.E. 2d 919 (2nd Dist., 1996) ("Illinois Bell"), wherein the appellate court found that:

> Where utility's exposure to risk is one iota greater, or it pays one dollar more for capital because of its affiliation with unregulated or nonutility company, (the) Commission must take steps to ensure that such increases do not enter into it rate of return calculations.

Based on the evidence presented, the Commission can only conclude that there has been an increased cost to AmerenCILCO for long-term debt due to the presence of its unregulated affiliates, CILCORP and AERG. Staff has made a persuasive showing that but for these unregulated affiliates, AmerenCILCO would have been assigned a more favorable debt rating and would have been able to accomplish the December

2008 bond issue at a lower interest rate, as suggested by Staff. Therefore, the Commission will adopt Staff's proposed cost of long-term debt rate of 6.69% for AmerenCILCO, 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.

2. AmerenCIPS

Staff and AmerenCIPS agree that for the purpose of this case, AmerenCIPS' December 31, 2008, embedded cost of long-term debt equals 6.49%. AmerenCIPS' embedded cost of long-term debt reflects Staff's adjustment to remove any incremental cost increase due to AmerenCIPS' decision to refinance the 4.7% intercompany note with 6.7% bonds during June 2006. Both parties note that the Commission adopted this adjustment to AmerenCIPS' embedded cost of long-term debt in AIU's most recent rate cases, Docket Nos. 07-0585 et al. (Cons.). For the purposes of the instant case, AmerenCIPS accepted Staff's adjustment. The Commission finds the agreed embedded long-term cost of debt for AmerenCIPS of 6.49% to be reasonable and it will be adopted for this proceeding.

3. AmerenIP

a. AmerenIP Position

AmerenIP proposes an embedded cost of long-term debt of 7.94% as of March 31, 2009. AmerenIP notes that it issued $400 million of long-term debt in October 2008, which Staff proposes to adjust to $350 million. Based on this reduction, Staff proposes to reduce the total debt expense and debt discount based on the lower principal amount. As AmerenIP argues that Staff's exclusion of a portion of the principal amount of AmerenIP's long-term debt issuance is improper, AmerenIP believes Staff's adjustments to the long-term cost of debt are equally misplaced and should be rejected.

b. Staff Position

Staff's calculation of AmerenIP's March 31, 2009, embedded cost of long-term debt equals 7.83%. Under Staff's alternative proposal for AmerenIP's capital structure, as described previously, AmerenIP's embedded cost of long-term debt also equals 7.83%, while AmerenIP proposes a 7.94% embedded cost of long-term debt. The only contested issue between Staff and AmerenIP relating to long-term debt is the previously described adjustment that Staff proposed to the amount of IP's 9.75% bond issuance, which also affects AmerenIP's embedded cost of long-term debt.

c. Commission Conclusion

As the Commission has previously accepted Staff's recommendation to reduce AmerenIP's long-term debt balance by $50 million, the Commission finds it appropriate to adopt Staff's suggested embedded cost of long-term debt of 7.83%. The

Commission finds this cost rate to be reasonable and it will be adopted for the purposes of this proceeding.

E. Bank Commitment Fees

1. AIU Position

While AIU accepts Staff's proposal that bank facility costs should be recovered by a direct adder to each of the AIUs' cost of capital, AIU argues that Staff witness Phipps makes errors in her allocation of the fees, and thus understates the overall cost of capital. AIU avers that Ms. Phipps erroneously assigns a lower amount of total upfront fees than the amount actually realized by AIU in connection with putting the Illinois Facility in place. AIU indicates that Ms. Phipps' calculations utilize a 1.50% - 1.75% upfront fee rate range rather than the 1.50% - 2.00% upfront fee range incurred. AIU opines that this is due to assuming that the various facility commitment levels, or tiers, and their corresponding upfront fee rates are based on a certain total size of all commitments, and Ms. Phipps therefore reduces those tiers based on the smaller size of the Illinois Facility, $800 million ("the Illinois Facility") relative to the total size of the Ameren facilities being arranged at the time, $2.15 billion ("the Missouri Facility"). AIU suggests it is wrong to suggest that banks would be willing to lend into a smaller facility at a 1.50% rate. AIU submits if it had only been arranging the $800 million Illinois Facility and not a total of $2.1 billion of multiple credit facilities it would have still paid upfront fee rates in the 1.50% - 2.00% range; it would have simply required participation from fewer lenders and/or smaller commitments from these lenders with a corresponding reduction in various commitment level tiers in dollar terms.

AIU argues that Ms. Phipps also allocates the bank fees incorrectly to the various parties of the Illinois Facility as she subtracts Ameren's entire sublimit, along with an equal proportion of the costs, under the facility from the total facility size rather than the total sublimits of the participants. While Staff argues that AIU's methodology of allocating the facility fees does not recognize that Ameren's sublimit could reduce AIU's borrowing capacity to $500 million from $635 million, AIU opines that Staff's approach would assign too much cost to Ameren, and too little to AIU.

AIU notes that the parties to this facility and their individual borrowing sublimits consist of AmerenCIPS, $135 million; AmerenCILCO, $150 million; AmerenIP, $350 million; and Ameren, $300 million. AIU notes that the sublimits total of $935 million obviously exceeds the size of the credit facility ($800 million), which AIU states is not unusual, as it is predicated on the assumption that borrowers' needs fluctuate and coincident borrowing at the maximum amount of each sublimit is rare. While it is true that Ameren could at any time borrow up to its sublimit of $300 million and reduce the amount available to the AIUs under the facility to $500 million from $635 million, AIU avers that Ms. Phipps' methodology wrongly assumes that Ameren will consistently do so over the life of the facility and ignores the fact that Ameren may borrow under the facility in order to provide funds to the AIUs. AIU opines that the sublimits in the case of the AIUs also reflect their mortgage bond capacities since the security of the mortgage bonds was a necessity to the participating lenders.

AIU argues that Ms. Phipps also ignores the fact that Ameren can and does from time to time provide supplemental liquidity to the AIUs and can act as their ―lender of last resort" when their individual borrowing sublimits are at their maximum and there is no additional liquidity available in the utility money pool. AIU notes that this was the case between October 27, 2008, and October 29, 2008, when Ameren lent between $4.1 million and $13.6 million into the utility money pool at a time when AmerenCILCO's credit facilities sublimit total of $150 million was at capacity and the other AIUs did not have any additional funds to lend.

AIU further notes that third quarter borrowing, representing the initial quarter that the Illinois Facility was in place, shows that Ameren's average daily amount outstanding was $133.3 million, far less than the $300 million assumed by Ms. Phipps in her analysis.

AIU submits that the objective of allocating the costs of the facility is to do so fairly so as to not overcharge or undercharge AIU's fair share of the fees. AIU argues this can be accomplished by allocating the total bank facility fees by each borrower's proportion of the total borrower sublimits under the facility, which would set AIU's collective allocation of the total Illinois Facility fees at 67.9%, rather than at 62.5%, as Staff suggests. AIU avers that this method of allocation is fair in that it does not show bias toward any borrower beyond what its individual sublimit implies. AIU submits that under Staff's approach, it could borrow over 79% of the available facility (not counting any borrowings by Ameren on its behalf), but bear just 62.5% of the cost, whereas weighting cost responsibly in proportion to sublimits is far more reasonable.

While Staff claims that the examples supporting AIU's position that smaller facilities and bank commitments can have higher commitment fee rates have no value, AIU submits that they are completely on point. AIU points to a recent Integrys Energy Group, Inc. ("Integrys") facility, where the amount of the financing was a fairly minor portion of Integrys' aggregate bank facilities, yet it attracted a higher upfront fee. (Ameren Ex. 37.0 Revised at 4)

AIU argues that each bank financing is different with its own unique circumstances. AIU submits that these unique circumstances include, but are not limited to, absolute size of the facility, size of the facility relative to the borrower's total facilities, borrower's credit ratings, date the facility is put in place, opportunity for ancillary business and terms of the facility (tenor, existence of an extension option, security, etc.). While Staff suggests a lowering of the upfront fee rate to the lowest rate tranche for the aggregate Ameren facilities is proper, AIU avers that as each deal presents a unique set of circumstances and involves a negotiation process with a unique group of financial institutions, the correct adjustment is to maintain the same upfront fee rate that the banks agreed to pursue to the actual negotiations.

AIU opines that Staff's position assumes Ameren's borrowing in this facility will crowd out AIU, thus not allowing AIU full sublimit access; however, AIU submits that history shows such a case is very unlikely. AIU notes that over the past two years (371 total days) there have been only two days that more than one of the AIUs has borrowed at their sublimit on the same day, while over the same time period aggregate AIU borrowing has exceeded $500 million on just 53 days. AIU avers that borrowers' needs fluctuate and coincident borrowing at the maximum amount of each sublimit is rare, while Ameren also has access to $1.3 billion of credit facilities outside of the Illinois Facility at a lower rate. AIU argues that this gives Ameren a financial incentive to borrow from the other facilities, which it appears Ameren has adopted, as its average daily borrowing from the Illinois Facility is $81 million while over the same period it was borrowing at an average rate of $302 million per day from the other facilities. AIU therefore submits that the Commission should adopt its position on allocating the credit facility fees.

2. Staff Position

Staff notes that Ameren established two credit facilities in June 2009, the $800 million Illinois Facility, and the $1,150 million amended and restated Missouri Facility that covers AmerenUE, AERG, and Ameren. Staff recommends allocating annual bank commitment fees of $1,467,431 to AmerenCILCO; $1,453,649 to AmerenCIPS; and $3,768,782 for AmerenIP. Staff calculates these amounts by reducing the amount of upfront fees from $15,505,000 to $12,205,000, and allocated 62.5% of all fees to AIU. Staff further reduces the facility fees for AmerenCILCO to reflect its stand-alone S&P credit rating, and for AmerenIP to reflect its Moody's credit rating upgrade during August 2009. Staff notes that AIU allocates 67.9% of the fees to AIU, including $15,505,000 in upfront fees. Staff avers that it calculates the cost of bank commitment fees that should be added to each company's cost of capital by dividing each company's total bank commitment fees by total capitalization. Hence, Staff recommends adding 28 basis points to AmerenCILCO's overall cost of capital; 15 basis points to AmerenCIPS' overall cost of capital; and 16 basis points to AmerenIP's overall cost of capital.

Staff opines that Section 9-230 of the Act, states, in part as follows:

> In determining a reasonable rate of return upon investment for any public utility in any proceeding to establish rates or charges, the Commission shall not include any . . . increased cost of capital . . . which is the direct or indirect result of the public utility_saffiliation with unregulated or nonutility companies.

Staff notes that the legislature used the word "any" to modify its prohibition of considering increased cost of capital in determining a reasonable ROR. Staff opines that this language prohibits the Commission from considering what portion of a utility's increased cost of capital caused by an affiliation is reasonable and, therefore, should be borne by ratepayers. Staff notes that in the Illinois Bell case, 283 Ill. App. 3d at 207, the court held that if a utility's exposure to risk is one iota greater, or if it pays one dollar more for capital because of its affiliation with an unregulated or non-utility company, the Commission must take steps to ensure that such increases do not enter in its ROR calculation. Staff argues that it would therefore be improper to reflect any resulting incremental cost increase in AIU's cost of capital, regardless of any potential benefits of either jointly negotiating the Illinois and Missouri credit facilities or including Ameren as a borrower under the Illinois credit facility.

While AIU objects to Staff's calculation of the amount of upfront fees, which removed any incremental cost resulting from higher upfront fees based on aggregate commitment under the Illinois and Missouri Facilities combined than would result from the Illinois Facility commitments only, and further object to Staff's allocation of bank commitment fees between Ameren and AIU because Staff reduced the combined AIU sublimits, Staff submits that this is the only proper result under ratemaking principles.

Staff also calculated one-time upfront fees for AIU to maintain its bank lines of credit, which vary from 1.5% to 2.0% of the aggregate amount of each lender‘s commitments under both the Illinois and Missouri Facilities and increase as the commitment amount increases. Staff avers that this calculated upfront fee is $12,205,000, based on each lender‘s commitments under the Illinois Facility.

Staff argues that the smaller credit facilities cited by AIU, Integrys and NiSource, Inc. ("NiSource"), for the proposition that a smaller credit facility would not necessarily have lower upfront fees, are not relevant to this position. AIU notes that each cited financing had 2% upfront fees, as opposed to Staff's suggested 1.5% fee for AIU. Staff avers that the Integrys $500 million financing actually replaced a small portion of Integrys' $2.2 billion credit facilities, while the NiSource financing is distinguishable from the Illinois Facility because NiSource entered a term bank loan to supplement $1.5 billion revolving credit facilities. Staff argues that a term bank loan is not a credit facility. Staff avers that these financings were entered into prior to the date AIU closed on the Illinois Facility and the amount of each of the credit facilities lenders‘ commitments to the borrowers is unknown.

While AIU argues that there is no reason the Illinois Facility should have a lower upfront fee than the larger aggregate Ameren facilities, implying there are economies of scale associated with a larger credit facility, Staff opines that under the terms of the Illinois Facility, upfront fees increase as commitment amounts increase.

Staff states it divided one-time costs between AIU and Ameren according to borrower sublimits under the Illinois Facility, as the borrower sublimits total $935 million; however, combined Illinois Facility borrowings can not exceed $800 million. Staff argues that as Ameren can borrow up to $300 million, the Illinois credit facility could at times effectively reduce AIU sublimits to $500 million, or 62.5% of the $800 million Illinois Facility, therefore Staff allocated $1,000,000 in arrangement fees, $7,628,125 in upfront fees, and $23,438 in annual administrative agency fees to the combined AIU.

While AIU alleges that this calculation assumes that Ameren will consistently borrow up to its sublimit over the life of the Illinois Facility, Staff opines that without this adjustment, AIU, and ultimately AIU customers, would pay costs associated with more credit facility capacity than it would have available if Ameren borrows more than $165 million under the Illinois Facility, which Staff notes occurred during July and August 2009.

While AIU asserts that Staff‘s methodology does not recognize that Ameren may borrow under the facility to provide AIU supplemental liquidity by acting as its ―lender of last resort," Staff avers that this argument does not support AIU's claim that AIU should pay costs associated with the $135 million borrowing capacity that either AIU or Ameren could borrow. Staff opines that the AIU argument applies only to borrowing capacity over the aggregate AIU sub-limit of $635 million because, under the Illinois Facility, Ameren pays a higher short-term bank loan rate than any of the AIUs due to its Baa3/BBB- unsecured debt ratings from Moody‘s and S&P. Staff states it is clear the Commission‘s rules for utility money pool agreements prohibits utilities borrowing from affiliates whenever utilities may borrow at lower cost directly from banks or other financial institutions.

Although AIU argues that Ameren has access to $1.3 billion of credit facilities outside the Illinois Facility at a rate that is slightly lower than the rate it can borrow from the Illinois Facility, giving it a financial incentive to borrow from the other facilities, Staff opines that this wrongly implies that Ameren can borrow $1,150,000,000 – its entire sub-limit under the Missouri Facility – for the entire two-year term of the Missouri Facility at lower cost than Ameren can borrow from the Illinois Facility. Staff states that AIU fails to note that these lower borrowing costs are available only from ―Declining Lenders” through July 14, 2010. Staff states that ―Declining Lenders” are those lenders under the original Missouri Facility that declined the option to extend their original commitments beyond July 14, 2010.

Staff avers that amending and restating the 2006 and 2007 Illinois credit facilities would have benefited AIU by making lower borrowing rates available from Declining Lenders, citing the fact that under the prior facility‘s pricing schedule, the spread over LIBOR for a Level III borrower equals 0.60%, while the current spread over LIBOR for a Level III borrower equals 2.75%. Despite that, Staff notes that Ameren terminated the 2006 and 2007 Illinois credit facilities seven months before they expired.

Staff avers that Ameren is not obliged under any agreement to provide AIU supplemental liquidity, and in fact, Ameren has taken steps to insulate itself from AIU when the Illinois legislature was considering rate freeze legislation by removing AIU as borrowers under Ameren‘s credit facility and removing provisions from the credit agreement that would treat AIU as subsidiaries for purposes of cross-default provisions.

Staff opines that AIU ignores the rationale for a commitment fee, which as its name implies, compensates banks for making a firm commitment to provide up to a specified amount of credit on demand. Staff argues that the full commitment fee applies regardless of the amount of money borrowed or letters of credit issued by each borrower. Staff argues that because of the overlapping sublimits in the Illinois Facility, the commitment available to AIU is a function of the amount of credit already committed to Ameren, which means AIU can only count on $500 million of the Illinois credit facility, not the $635 million of its combined sublimits would otherwise suggest.

While AIU argues that adjusting the facility fee rates for AmerenCIPS and AmerenIP in response to Moody's ratings upgrades for AIU on August 13, 2009, is improper, Staff notes that prior to the August 2009 rating upgrade by Moody's, AmerenCIPS was a Level III borrower, and AmerenIP was a Level IV borrower. Staff argues that the Moody's upgrade did not change AmerenCIPS' Level III borrower status, but instead raised AmerenIP's borrower status to Level III from Level IV.

Staff disputes AIU's argument that using AmerenIP's current senior secured credit rating is a selective adjustment to the cost of capital. Staff explains that the adjustment is not the consequence of an out-of-measurement period change in capitalization, such as the issuance of new debt or common equity, the retirement of debt, or the payment of common dividends. Staff notes that selective capital structure adjustments such as those would be improper because they wrongly imply those events occur in isolation. Staff avers that while facility fees will change during the term of the credit agreement as each borrower's credit rating changes, the change in the fee rate does not significantly affect the amount of capital the utility needs to maintain. Staff argues that adjustable facility fee rates are similar to variable interest rates, which the Commission has estimated using current rates rather than those that were in effect during a historical measurement period. Staff further notes that if AIU's argument had any merit, then AIU cost of capital could not reflect any costs associated with the 2009 Illinois Facility because AIU was a borrower under the 2006 and 2007 credit facilities on the capital structure measurement dates.

3. Commission Conclusion

The Commission notes that the principal difference between the parties on this issue is that AIU weights each individual company's allocation in proportion to total borrowing sublimits, while Staff does not. AIU argues that the effect of this is that under Staff's approach, the three utilities could borrow 79.4% of the available facility, while bearing responsibility for only 62.5% of the associated bank commitment fees. AIU states that Staff assumes that utility borrowing would be limited to 62.5%, when there is no such strict limitation on AIU. AIU argues that the more reasonable approach is that of AIU: weight the allocation based on sublimits. Under AIU's approach, the utilities bear 67.9% of the commitment fees, while being able to borrow between 62% and 79.4% of the facility. Staff takes the position that to allocate 67.9% of the commitment fees to AIU has the potential of subsidizing Ameren, should Ameren choose to borrow its maximum of $300 million of the credit facility. As this would leave only $500 million available to borrow by AIU, such a borrowing by Ameren would cause AIU to pay a greater portion of the commitment fees than allowed by Section 9-230 of the Act. The Commission is rightfully concerned that the ratepayers of AIU not subsidize the cost of

Ameren's borrowing, and therefore the Commission will adopt Staff's proposal on this issue.

The Commission will also adopt Staff's adjustment to reduce the amount of fees associated with the Illinois Facility. Staff postulates that there were no benefits to jointly negotiating that Facility with the Missouri Facility and that the allocation of overall costs to the Illinois Facility was too high. The Commission finds Staff's arguments on this issue convincing, and will adopt Staff's proposed facility fee adjustments for the purposes of this proceeding.

F. Cost of Short-Term Debt

1. AmerenCILCO

AmerenCILCO maintains that its cost of short-term debt is 2.15%. As AmerenCILCO does not have any short-term debt currently outstanding, the cost of short-term debt was calculated in accordance with the terms of the source of AmerenCILCO‘s last short-term borrowing—its credit facilities. AmerenCILCO states the cost is the sum of the April 30, 2009 one-month LIBOR and the applicable margin, which is based on both AmerenCILCO‘s current senior secured credit ratings (Baa2/BBB+) and the current utilization of the facility at the time of the loan. Staff proposed in its Initial Brief a cost of short-term debt for AmerenCILCO of 2.5%, however in its Reply Brief, Staff recommended a cost of short-term debt of 2.15%, in accordance with the recommendation of AmerenCILCO. As the parties appear to be in agreement on this issue, the Commission will adopt a cost of short-term debt for AmerenCILCO of 2.15% for purposes of this proceeding.

2. AmerenCIPS

Staff and AIU agree that AmerenCIPS‘ cost of short-term debt equals 1.50%. Staff calculated AmerenCIPS‘ weighted cost of short-term debt based on the proportion of AmerenCIPS‘ borrowings at a bank loan rate of 3.02% and an internal money pool rate of 0.19%. In her Direct Testimony, Ms. Phipps stated that during the short-term debt period, 46% of the Company‘s short-term borrowings were at the bank loan rate and 54% were at the internal money pool rate. Thus, Ms. Phipps maintains the weighted average interest rate for AmerenCIPS' short-term debt equals 1.50%. While AmerenCIPS disagreed with Ms. Phipps' reasoning for not including upfront facility fees in A&G expenses, Mr. O‘Bryan accepted her general methodology for the calculation of the costs and the addition of these costs as a direct adder to AmerenCIPS‘ of capital. AmerenCIPS does not contest Staff‘s adjustments, as the updated weighted average cost of capital schedule in Ameren Ex. 37.1 reflects a 1.50% weighted cost of short-debt for AmerenCIPS. The Commission finds that the parties agree that an appropriate cost of short-term debt for AmerenCIPS is 1.50%. The Commission finds this amount to be reasonable and it will be adopted for the purposes of this proceeding.

3. AmerenIP

Staff and AIU agree that AmerenIP's cost of short-term debt equals 3.02%. AmerenIP does not contest Staff's adjustments, as the updated weighted average cost of capital schedule in Ameren Ex. 37.1 reflects a 3.02% weighted cost of short-debt for AmerenIP. The Commission finds that the parties are in agreement that the cost of short-term debt for AmerenIP is 3.02%. The Commission finds this amount to be reasonable and it will be adopted for the purposes of this proceeding.

G. Cost of Common Equity

1. AIU Position

a. Return on Equity Estimates

AIU witness McShane recommends for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP, the cost of common equity is 11.2%, 10.8%, and 11.2%, respectively. For the electric operations, the recommended cost of common equity is 11.7%, 11.3%, and 11.7%, respectively.

AIU notes that Staff, IIEC, and CUB have also recommended costs of common equity. Staff calculates costs of equity for the gas operations as 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP. For electric delivery service operations, Staff recommends costs of common equity of 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP. IIEC proposes a combined ROE of 10.0% for AIU that reflects AIU's actual combination gas and electric investment fundamentals, while AG/CUB calculates that the cost of common equity for AIU's electric operations is 8.76% and the cost of common equity for AIU's gas operations is 7.97%.

AIU notes that each party bases its analysis on a sample group for the respective service because AIU's operations should reflect the risk profile and cost of equity of comparable utilities. For AIU's gas operations, Ms. McShane selected a sample of nine comparable gas local distribution companies (―LDCs") according to certain criteria specified in her Testimony. For AIU's electric operations, Ms. McShane selected a sample of 29 electric utilities according to similar criteria specified in her Testimony. Staff witness Freetly uses the same gas sample as Ms. McShane and a subset of her electric sample. IIEC witness Gorman and CUB witness Thomas both rely on the same electric and gas proxy groups as Ms. McShane.

In its Reply Brief, AIU argues the Commission's January 21, 2010 decision in the Peoples/North Shore rate case, Docket Nos. 09-0166/09-0167 (Cons.) supports AIU's suggested use of a constant growth discounted cash flow ("DCF") model and argues that the Commission should follow its reasoning as expressed in that Order.

b. DCF and CAPM Model Issues

AIU notes that Ms. Freetly and Mr. Gorman criticize the use of the comparable earnings test for determining the cost of equity, while Mr. Thomas asserts that the Commission has rejected the comparable earnings method in the past. AIU asserts that this criticism misinterprets Ms. McShane's use of the comparable earnings test in her cost of equity analysis. AIU argues that Ms. McShane agrees that the comparable earnings test does not measure the investor's opportunity cost of attracting equity capital as measured relative to market values; therefore she does not use the comparable earnings test to actually determine the cost of equity. Rather, AIU asserts that the comparable earnings test provides a measure of the fair return based on the concept of opportunity cost, and the returns earned by relatively low risk unregulated companies provide a relevant perspective on the reasonableness of the recommended ROE. AIU argues that the results of its comparable earnings test here indicate that AIU's proposed returns on equity, as calculated by the DCF and equity risk premium tests, are conservative when compared to the earnings level of relatively low risk unregulated companies.

AIU avers that Ms. Freetly's use of a multi-stage non-constant-growth quarterly DCF model is a departure from Staff's typical model – a constant-growth, single-stage, DCF model. AIU argues that this departure is not warranted in this case because analysts' forecasts are indeed the most objective measure of investor expectation embedded in the stock prices and dividend yields used to estimate the DCF cost of equity. AIU opines that Ms. Freetly admits she has previously relied on a constant-growth DCF model when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. AIU states Ms. Freetly's use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist.

c. Growth Rates

AIU notes that Ms. McShane relies on three DCF estimates: (1) a constant growth model that relies on analysts' earnings forecasts; (2) a sustainable growth model; and (3) a multi-stage model that includes both analysts' forecasts and nominal GDP growth as proxies for longer-term growth. AIU argues that because she weighs all three estimates, she incorporates a potential range of utility investor expected returns.

AIU observes that Ms. Freetly applies a multi-stage non-constant-growth quarterly DCF model to both her gas and electric samples, with her DCF analysis using three stages of dividend growth. AIU avers that Ms. Freetly's use of a multi-stage non-constant-growth quarterly DCF model is a departure from Staff's typical model, the constant growth (single stage) DCF model. AIU argues that Staff has not typically used a non-constant growth DCF model because it is more elaborate and has additional unobservable growth rate variables. AIU notes that Ms. Freetly argues that the levels of growth indicated by the average three- to five-year growth rates for her samples here are not sustainable over the long-term, largely because the analysts' growth forecasts for the samples are higher than the current growth expectations for the economy.

AIU opines that this departure is not warranted in this case, and argues that analysts' forecasts are the most objective measure of investor expectations that are embedded in the stock prices and dividend yields used to estimate the DCF cost of equity. AIU further notes that Mr. Freetly testified she has previously relied on a constant growth DCF model when analysts' consensus forecasts were higher than the forecast long-term growth in the economy. Ms. Freetly also uses a constant growth DCF test to develop her equity risk premium model; therefore AIU submits that if a constant growth DCF model is appropriate for the equity risk premium model, it is also appropriate for developing an expected return.

AIU avers that use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist and avoid potentially internally inconsistent results. As the multi-stage model can also create inconsistencies in the DCF cost estimates for the individual companies, AIU opines that it is more reasonable to give equal weight to the results of both the constant growth and multi-stage models.

AIU notes that in the final stage of her multi-stage DCF analysis, Ms. Freetly uses forward yields on the 20-year U.S. Treasury bonds as a proxy for long-term GDP growth, stating that the changes in the U.S. Treasury bond yield indicate that investors' current long-term expectations vary over time. Ms. Freetly argues the yield on U.S. Treasury bonds is a timely gauge of expected long-term economic growth because it reflects changing investor expectations due to current economic conditions, and posits that long-term forecasts, from which Ms. McShane implies that investor expectations of long-term growth are essentially static, might not be often updated.

While AIU admits Ms. Freetly is correct that the Blue Chip long-term consensus forecast of GDP growth extends only ten years, and that some long-term GDP forecasts are updated only annually or infrequently, AIU submits her arguments do not support the use of forward interest rates as a proxy for long-term GDP growth. AIU argues there is no basis to conclude that investors will not rely on forecasts of GDP over the next ten years as the best available estimate for very long-term growth and the stability of the Blue Chip ten-year consensus forecasts of GDP growth likely represents the expected reversion of growth to trend levels. AIU avers that compared to forward yields, it is more appropriate to use a direct estimate of long-term economic growth as provided by the consensus of economists' forecasts.

AIU opines that there are too many influences to conclude that the forward 20-year U.S. Treasury yield is a good proxy for investor expectations of long-term growth of the economy, with such factors as global influences on interest rate, high demand for U.S. securities, and the global savings glut putting downward pressure on U.S. Treasury bond yields. AIU notes that although the difference between the specific implied forward yield on the 20-year U.S. Treasury and the most recent consensus forecast of long-term economic growth is relatively small, the capital market experience over the past two years shows the differential can be substantial.

AIU avers that Ms. McShane applies an average daily stock price over a relatively short period of time when applying the DCF test, which Ms. Freetly criticizes and instead advocates a —spot" stock price. AIU opines that the price of a stock can rise or fall temporarily on any given day. AIU argues that —spot" stock prices are typically combined with a corresponding growth rate forecast, which may have been prepared and disseminated earlier, which may lead to a mismatch between the price and investor growth expectations – and thus, an erroneous DCF cost. AIU submits that the preferable price for the DCF test is an average daily price over a relatively short period of time.

AIU notes that Mr. Gorman employs three DCF models, a multi-stage model, a sustainable growth model, and a constant growth model, in which he gives his DCF and CAPM tests equal weight. AIU states that because he argues that AIU is a combination utility – a combined risk reflected in its bond rating, its operating risk, and the operating risk considered by its bond holders and equity holders – he recommends a single ROE to reflect this combined risk.

AIU disputes that because AIU is a combination of gas and electric utilities, the same cost of equity should apply to each of its operations. AIU opines that the return allowed for the electric utility operations should reflect the cost of equity for electric utility operations, and the same for the gas operations. AIU submits this combination results in cross-subsidies, erroneous investment decisions, and a misallocation of capital resources. AIU states that Staff agrees with AIU that the gas and electric operations should be considered separately to assign the proper ROR for each entity based on the level of operating and financial risk specific to the operations of each company.

While Mr. Gorman's initial sustainable growth DCF study ignored the external growth component, AIU notes that Mr. Gorman updated his sustainable growth model to add the component, but argue he failed to estimate it correctly, incorrectly assuming book values per share will increase while stock prices stay the same. AIU submits that Mr. Gorman's incorrect assumption about stagnant stock prices leads him to incorrectly conclude that the external growth component of the sustainable growth model is negative for the electric sample and minimal for the gas sample.

While Mr. Gorman criticizes the dividend yield in Ms. McShane's constant growth DCF studies based on his view that her dividend yields are abnormally high, AIU notes that during much of the five-year period of dividend yields he compares to recent years, the cost of capital was abnormally low, characterized by easy credit, low economic volatility, and a relatively high investor tolerance for risk. AIU submits that the landscape has since been altered by the financial crisis of 2008-2009, and the current dividend yields, therefore, are more representative of its historic average levels.

AIU notes that Mr. Gorman also challenges Ms. McShane's constant growth DCF because he believes it includes irrationally high growth, and thus, unreasonably inflates AIU's ROE. Although Mr. Gorman argues that short-term analysts' growth rates in the market today are too high to be reasonable estimates of sustainable long-term growth, AIU avers that he is incorrect as analysts do not make forecasts beyond five years, and therefore, it is not possible to determine whether investors implicitly expect the forecast growth rates to continue indefinitely and when any decline, if any, may occur. Accordingly, AIU submits the constant growth DCF model is the only model that fully retains the only objective evidence of investors' growth expectations.

AIU states that Mr. Thomas uses a three-stage DCF test, with the three stages being for the short-term that the sample companies will grow at their average internal growth rate over the last five years, for the long-term that growth for the sample companies will trend toward the historical average growth rate in real GDP, and in the final stage he uses a forecast of real economic growth, rather than nominal growth. AIU opines that Mr. Thomas' choice of historical period for the first stage is purely subjective and not related to investor expectations embedded in current stock prices, while with respect to the long-term growth rate; his use of a real rate of growth fails to consider that investors require both a real return and compensation for inflation. AIU argues that the studies do not suggest that the actual nominal rate of long-term growth has been equal to the real rate of growth in the economy or that the expected nominal rates of long-term growth should be equal to the real rate of growth in the economy, and do not support using a real rate of GDP growth as a proxy for investors' expected long-term growth.

AIU states that Mr. Thomas recommends that the Commission place less reliance on analysts' forecasts of growth in the DCF calculation. AIU avers that Mr. Thomas argues that, due to discontinuity in the equity markets and uncertainty in information, the Commission should base its analysis of the DCF growth component on three criteria: (1) earnings growth rate inputs that are reasonable in light of anticipated growth in GDP; (2) the long-term growth rate must not implicitly require continued earnings above the regulated firm's cost of equity, as derived in the analysis; and (3) the long-term growth rates must not require dividend payout ratios that are not consistent with the capital expenditure growth rate and the ROE. AIU opines that Mr. Thomas argues incorrectly that current analysts' three- to five-year growth projections do not meet these criteria, but rather, he asserts that research demonstrates analysts tend to be optimistic about future growth and produce upwardly-biased forecasts, which translate into DCF costs of capital above the true required cost of capital. While Mr. Thomas states that Ms. McShane's proposed growth rates would require that the sample companies exceed their own historic growth, AIU notes that the Commission has not previously accepted this argument. AIU argues that the studies that Mr. Thomas cites to support his opinion that analysts are optimistic about future growth rates are less applicable to utilities, and utilities can not expect similar results. AIU avers that Ms. Freetly agrees these studies tend to report generalized findings and do not specifically suggest that growth rates for utilities are overstated relative to achieved growth, further noting that other studies indicate that analyst growth rate estimates for utilities are not overstated.

AIU submits that Mr. Thomas' proposed ROE is not comparable to any cost of equity or return granted by other regulators, which is significant because the national average allowed ROE can be interpreted as a consensus assessment of the expert testimony that has been proffered by a wide range of stakeholders. AIU avers that the national average allowed ROE is a relevant indicator of the capital markets in which AIU will have to compete for capital. AIU opines that returns at the levels proposed by Mr. Thomas are significantly below any reasonable indicator of the returns investors expect to receive on investments of comparable risk, and would not allow the utilities to attract capital as required on reasonable terms or meet the comparable returns standard.

d. Beta

AIU notes that both Ms. McShane and Mr. Gorman apply Value Line (adjusted, weekly) betas to their CAPM analyses, while Ms. Freetly recommends equally weighing weekly and monthly betas, contending that neither weekly nor monthly betas are superior to the other. AIU avers that Ms. Freetly explains that the better type of beta estimate is unclear because both Value Line and regression betas are estimates of the unobservable true beta that measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. AIU opines that Ms. Freetly states that her method has been regularly used by both Staff and the Commission and employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology, while the Commission has rejected Ms. McShane's position in a prior proceeding.

AIU states that Ms. Freetly recognizes the strengths of weekly betas, but notes she asserts that weekly and monthly betas have strengths and weaknesses relative to each other, while recognizing that the standard deviation of weekly beta estimates is typically lower than for monthly beta estimates, making weekly betas usually more reliable. AIU avers Ms. Freetly incorrectly argues that non-synchronous trading is a problem with Ms. McShane's weekly data, but not for monthly data.

AIU asserts Ms. Freetly is incorrect when she asserts that non-synchronous trading is a problem with weekly betas. AIU states the non-synchronous trading effect arises when stock prices respond to economic events with a lag, which is a particular problem when analyzing daily data collected on thinly-traded stocks. AIU argues it is not a problem here because the companies are not thinly traded. Moreover, AIU avers that Ms. Freetly's analysis that portends to show a statistically-significant negative relationship between the lagged returns on the gas utilities and the returns on the equity market composite may actually relate more to the market conditions during the financial crisis than to non-synchronous trading issues. AIU opines that Ms. Freetly's calculation of the coefficient of variation for the monthly and weekly series of returns does not indicate that there is increased random error in the weekly series relative to the monthly series, but rather, higher coefficients of variation associated with weekly betas are consistent with higher weekly betas.

Staff argues that changes in risk can bias the beta estimate, asserting a decrease in a company‘s systematic risk can increase its estimated beta. Therefore, Staff avers that given the long time period examined in this case, one can not conclude that the Value Line betas underestimate actual returns or that using monthly returns would have further underestimated the actual returns for gas and electric utilities from those implied betas because the relatively high returns could be a consequence of declining systematic risk. AIU submits that greater confidence can be placed in weekly betas because weekly betas are less likely to be impacted by the presence of outlying observations, noting that weekly betas have five times as many observations, diluting the impact of observations that are outliers. AIU argues that regression betas calculated by Staff using monthly data have consistently been lower than the Value Line weekly betas, arguing that its analyses conclude that much greater confidence can be placed in weekly betas.

AIU notes that as Ms. McShane agrees that the calculated beta may decrease when ―true" systematic risk is rising and may increase when ―true" systematic risk is falling, she therefore compares a series of calculated betas for both the gas distributors and electric utilities to the average returns to assess whether, over time, the actual returns were in line with what the betas would have predicted. AIU avers that she concluded that the adjusted weekly Value Line betas underestimated the actual returns for both the gas distributors and electric utilities. While Staff faults Ms. McShane‘s analysis comparing weekly and monthly betas, AIU opines that Staff is incorrect in emphasizing Ms. McShane‘s report of the coefficient of determination ("R^2") and the statistical significance test and downplaying Ms. McShane‘s comments regarding the standard error, as AIU submits that standard errors are consistently lower and confidence intervals are consistently narrower for weekly betas, than monthly.

AIU states that Mr. Thomas recommends unadjusted, not Value Line, betas, asserting there is no evidence to support the rationale for the argument that utility betas trend toward the market mean of 1.0, citing financial literature purporting to demonstrate that the mean reversion adjustment is inappropriate and overstates the beta parameter. AIU notes that Mr. Thomas calculates corrected betas by removing the adjustment for each of the companies in his sample group, which AIU submits is incorrect. AIU avers there is significant empirical evidence indicating that ―raw" or unadjusted betas underestimate the returns of low beta stocks and overestimate returns of high beta stocks, stating the adjustment corrects for the empirically observed relationships between betas and returns. AIU notes that Mr. Thomas admits that the Commission has accepted a static beta adjustment in the past, although Mr. Thomas argues there is absolutely no evidence that a one-size fits all adjustment is reasonable. AIU notes that Staff agrees betas should be adjusted, stating that the texts cited by Mr. Thomas concedes that adjustments result in appreciably better forecasts, and further noting that Mr. Thomas‘ proposal has been explicitly rejected in prior rate cases.

e. Market Risk Premium

AIU states that the CAPM requires determining the equity risk premium required for the market as a whole, and then adjusting it to account for the risk of the particular security or portfolio of securities using the beta. AIU notes the result (market risk premium multiplied by beta) is an estimate of the equity risk premium specific to the particular security or portfolio of securities, and the required market risk premium varies with the outlook for inflation and other economic and capital market conditions, interest rates, investors' willingness to bear risk, and profits.

AIU opines that required expected market risk premium ("EMRP") can be developed from estimates of prospective market risk premiums and from an analysis of experienced market risk premiums. AIU avers the DCF model can be used to estimate the cost of equity where the expected return is comprised of the dividend yield plus investor expectations of longer-term growth based on prevailing capital market conditions. AIU states that for the DCF-based market risk premium, an estimate of a forward-looking market risk premium is valuable because the required market risk premium is not static, and thus, a direct measure of the prospective market risk premium may provide a more accurate measure of the current level of the expected differential between stock and bond returns than experienced risk premiums. AIU submits that an estimate of a forward-looking market risk premium provides value because the equivalence of past return to what were investors' ex ante expectations may be pure coincidence, and the determination of a fair ROE reflective of the expected interest rate environment requires a direct assessment of current stock market expectations.

AIU states the forward-looking market premium may be determined by an application of the DCF model to the S&P 500 with the inputs of an expected dividend yield and an expected growth rate. AIU avers that the expected dividend yield is equal to the average of the month-end February and March 2009 market-value weighted expected dividend yields for the S&P 500 companies of 3.7%, while for the expected growth rate, the market-value weighted consensus forecasts of earnings growth for the companies in the S&P 500 were used as a proxy for investor expectations of long-term growth. For the risk-free rate, AIU notes Ms. McShane uses the forecast 30-year U.S. Treasury yield expected to prevail over the same 5-year time frame for which the forecast growth rates for the market are made.

Because the equity markets are currently experiencing significant turmoil and uncertainty, AIU avers that Ms. McShane recommends giving greater weight to the DCF-based market risk premium than she has in the past. Given the extent of equity market risk at present, with the current level of the market risk premium higher by a significant margin than its long-term average, AIU notes Ms. McShane made two CAPM estimates of the cost of equity – one based on ex post market risk premiums and one based on an ex ante estimate of the market risk premium.

Based on the DCF-based market risk premium, AIU states the forward-looking estimate of the CAPM market risk premium amounts to 6.8%, which, with a dividend yield for S&P 500 of 2.1% and a consensus IBES forecast of 5-year growth of 9.63%, results in an expected market return produced by the ex ante DCF-based market risk premium approach of 12.0%. AIU avers that CAPM ROE produced by the ex post market risk premium approach is 9.7% for the gas sample and 10.3% for the electric sample. Because the DCF-based market risk premium approach explicitly captures current financial market conditions, AIU recommends that the CAPM ROE produced by the ex ante DCF-based market risk premium approach be given greater weight than the CAPM ROE produced by the ex post (or historic) market risk premium approach.

As the estimation of the EMRP from achieved (ex post) market risk premiums is premised on the notion that investors' expectations are linked to their past experience, AIU opines that basing calculations of achieved risk premiums on the longest periods available reflects the notion that it is necessary to include as broad a range of event types as possible to avoid overweighing periods that represent unusual circumstances. Since the objective of the analysis is to assess investor expectations in the current economic and capital market environment, AIU avers that weight should be given to periods whose equity characteristics are more closely aligned with what today's investors are likely to anticipate over the longer term. When an estimated market risk premium is developed from historic average returns, AIU argues that arithmetic averages need to be used, and the income return – not the total return on long-term government bonds – should be the measure of the historic risk-free rate used when calculating historic risk premiums.

AIU states that Ms. McShane also performs an equity risk premium test based on utility achieved risk premiums. Ms. McShane estimated the historic equity risk premiums for utilities relative to long-term A-rated public utility bonds and BAA-rated public utility bonds, and AIU avers she estimated the historic equity risk premium for utilities relative to long-term A-rated public utility bonds and Baa-rated public utility bonds at 4.5% and 4.25%, respectively. AIU opines that adding the historic spreads between the utility and bond yields to the long-term U.S. Treasury yield of 5.5% results in a forecast A-rated utility bond yield of 6.8% and a Baa-rated utility bond yield of 7.2%, and the resulting required equity returns are 11.3% and 11.5% for the gas and electric samples respectively.

AIU states that in Ms. Freetly's CAPM test, for the risk-free ROR; she examines the suitability of the yields on 4-week U.S. Treasury bills and 30-year U.S. Treasury bonds, using a 4.4% —spot” 30-year U.S. Treasury yield in deriving her CAPM estimate. AIU notes Ms. Freetly then estimates the expected ROR on the market by conducting a DCF analysis on the firms composing the S&P 500 as of June 30, 2009, with the resulting rates of return on common equity of 9.46% for the gas sample and 10.21% for the electric sample.

AIU opines that Ms. McShane also advocates using a longer-term U.S. Treasury, to more closely match the duration of the risk-free rate and common equities, whose values reflect expected cash flows that are perpetual in nature. AIU states that most analysts rely on a long-term government yield, which is risk-free in that there is no default risk associated with U.S. Treasury securities; therefore Ms. McShane utilizes forecast yields on the 30-year U.S. Treasury bond. AIU states the 30-year U.S. Treasury bond is once again considered a benchmark bond for the purpose of pricing securities.

While Ms. Freetly criticizes Ms. McShane's use of historical data in developing her market and utility equity risk premiums, AIU asserts it is unreasonable to expect investors to ignore returns they have achieved historically when forming their equity market return expectations going forward. AIU avers that without a discernable trend in achieved returns over time, as is the case here, historic returns provide a relevant perspective on the returns investors may reasonably expect over the longer term.

AIU argues that Mr. Gorman's CAPM analysis is inappropriately based on his market risk premium. AIU notes Mr. Gorman makes two estimates of the market risk premium: a forward-looking estimate and an estimate based on a long-term historical average. Although Mr. Gorman re-did his CAPM estimates to reflect Ms. McShane's proposed modifications to his market risk premium estimate, AIU states Mr. Gorman's risk premium method also incorrectly estimates the market return by adding an estimate of the long-term rate of inflation to the historic average real return. AIU argues the real return should be correlated with historical stock returns, which Mr. Gorman does not do. AIU avers that combining the average real return achieved on the market with expected inflation would be appropriate only if there were evidence that the expected return on the market moves in tandem with the rate of inflation, which has not been shown here.

AIU states Mr. Gorman's evidence on the market risk premium also does not address the fact that the historic measured risk premiums through 2008 were negatively impacted by the significant sell-off in the equity market in 2008. As the 2009 upswing in the equity market, through the end of October, indicates a higher measured equity market risk premium than did the values calculated through the end of 2008, AIU asserts Mr. Gorman's estimate of the market risk premium and resulting CAPM costs of equity are too low.

Although Mr. Gorman also performs a multi-stage DCF model to support his risk premium estimate, AIU avers his model assumes investors expect that analysts' forecasts of growth will persist for ten years and that growth will then drop precipitously to the expected nominal rate of growth in the economy. AIU argues the result of Mr. Gorman's model is well below his multi-stage DCF estimates for both the electric and gas samples, which does not help assess the reasonableness of Mr. Gorman's equity market risk premium estimate.

AIU notes that Mr. Gorman criticizes Ms. McShane's risk premium studies for their use of long-term forecasts of interest rate in conjunction with her historic risk premiums, as well as her use of forecast of utility bond yields, particularly in her application of the equity risk premium tests. However, AIU asserts that when conducting her equity risk premium tests by reference to historic average returns and risk premiums for both the market as a whole and for utilities, Ms. McShane combines a long-term average risk premium with long-term average expected bond yields. AIU argues the combination of a historic risk premium with a spot interest rate will result in an under- or over-estimation of the cost of equity at any given point in time, which produces an estimate of the cost of equity that matches the constancy of the equity risk premium implied by the use of historic averages with a similarly estimated interest rate.

AIU opines that Mr. Gorman himself uses forecasts of long-term U.S. Treasury interest rates in his CAPM, which is comparable to Ms. McShane‘s use of forecasts of utility bond yields. AIU avers that as the economy recovers, if long-term U.S. Treasury bond yields are expected to rise, so will utility bond yields, therefore Ms. McShane‘s analysis correctly incorporates the impact of the expected increase in long-term U.S. Treasury bond yields on the corresponding utility bond yields.

While Ms. Freetly and Mr. Gorman recommend the Commission use current or "spot" interest rates rather than forecast interest rates in Ms. McShane‘s risk premium studies, AIU notes that to estimate the risk-free rate, Ms. Freetly states she used current U.S. Treasury yields that reflect all relevant, currently available information, including investor expectations regarding future interest rates. Ms. Freetly asserts that investor appraisals of the value of forecasts are reflected in current interest rates, and therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates.

AIU states that —spot‖ U.S. Treasury yields remain at relatively low levels as a result of several factors, including the global demand for U.S. Treasury debt and relatively weak economic conditions. With the U.S. federal budget deficit for 2009 topping $1.4 trillion, AIU argues that the most likely trajectory for U.S. Treasury bond yields, as the U.S. global economies strengthen, is an upward trajectory. AIU opines that since such an upward trajectory is reflected in the consensus of economists‘ forecasts, which recognize that interest rates will rise as the economy improves, therefore the application of the CAPM should recognize the high probability that U.S Treasury yields will increase, making current interest rates inappropriate.

IIEC argues that Ms. McShane‘s market risk premium estimated from historic data is overstated because it relies on income returns rather than on total returns on U.S. Treasury bonds, and because of Ms. McShane‘s use of Morningstar data, which overstate the market risk premium that would be measured from total U.S. Treasury bond returns because Morningstar risk premiums are measured using the U.S. Treasury bond income returns. While AIU agrees that the estimated risk premium using income returns on U.S. Treasury bonds is higher than it would be if it were measured using total returns AIU asserts that IIEC ignores the fact that proper application of CAPM requires a risk-free rate, therefore the income return is the best representation of the true long-term historical risk free rate.

While Mr. Thomas argues that an EMRP of 5% may be too high, indicating that current academic research estimates range from 3.4% to 5.1%, AIU opines that there is no reason to conclude that equity market returns will be lower in the future than they were in the past and that historic evidence supports an equity risk premium equal to or slightly higher than 6.5%. As Ms. Freetly asserts, because the relationship between returns of the stock market and U.S. Treasury bonds is not stable over time, current returns provide the best indication of what investors are expecting going forward. AIU concurs with Ms. Freetly when she disagrees that the proper expected common equity market risk premium for determining the investor-required ROR is between 3% and 5%.

f. Proposed Adjustments

(1) Financial Risk

AIU states that to determine a fair ROE for a utility, it is vital to recognize that the cost of capital is determined in the capital markets and reflects the market value of firms' debt and equity capital, which may differ from book value capital structures. AIU recognizes that both it and Staff agree that a market-based cost of equity is appropriate and that it is necessary to use a book value rate base for regulatory rate setting. Further, AIU notes that both agree that differences in financial risk must be accounted for in the cost of equity and that higher or lower financial risk than the proxy companies, given similar business risk, requires an adjustment to the proxy companies' costs of equity, however the issue is how to measure those differences.

AIU avers that Ms. McShane uses two approaches to quantify the impact of a change in financial risk on the cost of equity. AIU states her first approach is based on the widely accepted view that the overall cost of capital does not change materially over a relatively broad range of capital structures, while her second approach is based on the theoretical model that assumes that the overall cost of capital declines as the debt ratio rises due to the income tax shield on interest expense. AIU submits the latter approach will overestimate the impact of leverage on the overall cost of capital and understate the impact of increasing financial leverage on the cost of equity because that approach does not account for any of the factors that offset the corporate income tax advantage of debt.

AIU avers that to apply these approaches, Ms. McShane first determines the market value capital structures of the sample companies over the period corresponding to the relevant period of analysis for the specific cost of equity. AIU states she then estimates the utility samples' weighted average cost of capital using market value capital structures and the appropriate market value common equity ratio and cost of equity. Finally, she estimates the change in common equity return requirement for each of her tests (DCF, CAPM, and DCF-based risk premium tests) to account for the difference between the sample average market value common equity ratio and the company's book value common equity ratio. AIU opines that if the difference between the company's ratemaking common equity ratio and the relevant market value common equity ratios results in an adjustment, Ms. McShane recommends that the allowed ROE be adjusted accordingly. AIU argues that Ms. McShane's method has been accepted by other regulators in the past.

While AIU recognizes that in the past the Commission has rejected Ms. McShane's approach because the AIUs do not have market traded stock, AIU avers that applying a market-derived cost of equity to the book value (ratemaking) capital structure without recognizing the financial risk differences between the market value capital structures that underpin the estimates of the cost of equity and the book value capital structures of the AIU utilities will understate AIU's cost of equity. AIU opines this lack of observable market value capital structures for AIU does not alter this conclusion because the relevant comparison is between the financial risk inherent in the market value capital structures of proxy utilities and the financial risk inherent in the book value (ratemaking) capital structures of AIU.

AIU states that for each AIU gas utility relative to the gas sample, Ms. Freetly concludes that her revenue requirement recommendations, including her cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa3 credit rating for AmerenCILCO Gas, an A3 credit rating for AmerenCIPS Gas, and a Baa3 credit rating for AmerenIP Gas. AIU notes that Ms. Freetly believes the gas sample's level of financial strength indicates it has more financial risk than AmerenCIPS and less financial risk than AmerenCILCO and AmerenIP. Given the difference between the credit ratings commensurate with the forward-looking financial strength of AIU gas operations and the credit rating commensurate with the gas sample, Ms. Freetly recommends that the sample's average cost of common equity be adjusted to determine the estimate of each company's cost of common equity, using the spreads for 30-year utility debt yields as of August 31, 2009. Ms. Freetly recommends a 10.5 basis point adjustment for AmerenCILCO and AmerenIP and a decrease of 15 basis points for AmerenCIPS.

AIU submits that for each AIU electric utility relative to the electric sample, Ms. Freetly concludes that her revenue requirement recommendations, including cost of common equity recommendations, indicate levels of financial strength commensurate with a Baa1 credit rating for AmerenCILCO, an Aa3 credit rating for AmerenCIPS, and a Baa2 credit rating for AmerenIP. According to Ms. Freetly, the electric sample has a lower average implied credit rating, which indicates that its financial risk is higher than that of either AmerenCILCO's or AmerenCIPS' electric delivery service operations. Given the difference between the implied forward-looking credit ratings for the Companies and the average credit rating of the electric sample, Ms. Freetly recommends that the sample's average cost of common equity be adjusted to determine the estimate of each company's cost of common equity. To make the adjustments to the cost of common equity of the electric sample, Ms. Freetly used Reuters Corporate Spreads for Utilities from August 31, 2009. Her analysis recommends a cost of equity adjustment for the electric operations of 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS. This equates to a 0.06% downward adjustment for AmerenCILCO and a 0.30% downward adjustment for AmerenCIPS. Ms. Freetly does not recommend adjusting for AmerenIP because the financial ratios for AmerenIP are commensurate with the same level of financial risk as the electric sample.

AIU argues that Ms. Freetly‘s adjustments are incorrect, in part because they are based on the assumption that AIU will achieve the credit metrics implicit in Staff‘s recommendations. While Ms. Freetly claims that Staff‘s revenue requirement recommendations, including her cost of common equity recommendations, indicate credit metrics commensurate with higher or lower debt ratings than the implied debt ratings suggested by the credit metrics of her utility samples, AIU avers that her comparisons are flawed because she compares credit metrics that her utility samples have actually achieved from 2006-2008 with credit metrics that could be achieved if AIU were able to earn the returns on equity that they are allowed. AIU submits that recent history, however, demonstrates AIU has significantly under-earned its allowed returns on equity and thus has not achieved the levels of financial strength assumed by Ms. Freetly‘s financial risk adjustments. By comparing the potential financial performance and credit metrics of AIU to the actual financial performance and credit metrics of the proxy utilities, Ms. Freetly understates AIU's financial risk relative to the proxy utilities.

Further, while Ms. Freetly‘s adjustments assume an equity investor quantifies financial risk differences identically to a bond investor, AIU avers that proper financial risk adjustments to the cost of equity for the electric and gas samples consider the higher or lower return that equity investors require for bearing the higher or lower financial risk inherent in AIU's proposed ratemaking capital structures. AIU submits that Ms. Freetly is also incorrect when she contends that Ms. McShane‘s adjustments would perpetuate further increases in earnings and the market value of the stock. Earnings, dividends, book, and market values increase at the same rate, arguing changes in the market/book ratio should occur only if the cost of capital or the expected return on book equity changes.

AIU notes that Mr. Gorman also disagrees with Ms. McShane‘s financial risk adjustment, asserting it inflates a fair and reasonable return. While Mr. Thomas disagrees with adjusting the market-based DCF model results before applying them to the book value of assets in rate base, arguing that the adjustment inflates the market-based DCF cost of equity and that no such adjustment is required, AIU opines that Mr. Thomas' recommended returns are too low and would deprive AIU of a chance to earn a return commensurate with those of comparable risk firms.

(2) Fixed Customer Charge

AIU notes Ms. Freetly recommends an additional downward adjustment to the gas distribution operations‘ Rate of return on common equity based on the Commission‘s recognition, in AIU‘s last rate cases, that the AIU gas utilities‘ move toward more fixed cost recovery – through the fixed monthly charge – gives AIU more assurance of recovering its fixed costs of service for gas operations. As Ms. Freetly contends this cost recovery reduces risk and provides greater assurance that the authorized ROR will be earned, she therefore recommends a downward adjustment of

10 basis points to the AIU gas utilities' Rate of return on common equity – the same adjustment the Commission found proper in the last rate cases.

AIU claims that Ms. Freetly disregards the fact that eight of the nine gas distributors in the gas sample have similar mechanisms in place; therefore the cost of common equity estimate for the sample already reflects the risk reduction. While Ms. Freetly argues that some of the mechanisms apply only to portions of a company's service territories, AIU opines if equity investors impute lower risk due to the adoption of such mechanisms, lower risk would already be reflected in the cost of equity estimates for the sample companies. AIU argues that Ms. Freetly's recommended reduction would double count the risk reduction that might be imputed by investors and should thus be rejected.

(3) Uncollectibles Riders

While Ms. Freetly asserts the uncollectible riders would reduce AIU's risk because they would reduce uncertainty of cash flows, AIU notes she admits she is unaware of an established approach for gauging the effect that adoption of the riders would have on investor perceptions of AIU's risk levels and the resulting costs of equity. AIU states she instead proposes adjustments for the riders, based on two distinct approaches: (1) estimate the effect of the adoption of the riders on AIU's Moody credit ratings, and then, adjust based on the resulting change in implied yield spreads; and (2) adjust cost of common equity downward to offset the increased operating income resulting from the adoption of the riders. AIU opines that like Ms. Freetly, Mr. Thomas states that the riders will reduce both uncertainty of cash flows and AIU's risk, but as he is not aware of an approach to gauge the effect of the riders, he therefore supports Ms. Freetly's methodology as reasonable, although conservative.

AIU notes that for her first approach, Ms. Freetly assumes the credit rating assigned to the —ability to recover costs and earn returns" factor would improve by one credit rating with the implementation of the uncollectibles rider, while for her second approach, Ms. Freetly adjusts her cost of common equity downward to offset the increased operating income resulting from the adoption of Rider GUA-Gas Uncollectible Adjustment ("Rider GUA"). AIU states she adjusts her cost of common equity downward until the pro forma operating incomes under Rider GUA equal the original pro forma operating incomes she calculated for AIU without Rider GUA. For the electric operations, AIU says Ms. Freetly estimates the incremental recovery of uncollectibles expense had Rider EUA-Electric Uncollectible Adjustment ("Rider EUA") been in effect for the past ten years, then adjusting her cost of common equity downward until the pro forma operating incomes under Rider EUA equal the original pro forma operating incomes she calculated for AIU without Rider EUA.

AIU states Ms. Freetly averages the results of her two approaches to determine her recommended adjustments for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 63, 64.5, and 34 basis points, respectively, to reflect the reduced risk due to Rider EUA; while she recommends adjustments to the costs of common equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 87.5, 79.5, and 60.5 basis points, respectively, to reflect the reduced risk due to Rider GUA.

AIU argues Ms. Freetly‘s approaches are both flawed. AIU opines Ms. Freetly is incorrect to assume that the credit rating of Moody‘s —ability to recover costs and earn returns" will increase by one full credit rating as there is no empirical evidence to support that assertion. AIU avers that Ms. Freetly‘s assumption that Moody‘s would change both the —regulatory framework" and —sustainable profitability" factors by a full credit rating for the adoption of the riders is without merit. AIU claims Moody‘s already acknowledged the legislation and factored it into its decision to upgrade AIU to investment grade, so the actual adoption of the riders is unlikely to result in a full credit rating improvement in both regulatory framework and sustainable profitability. AIU states that even if this were the case, AIU would still have equivalent credit ratings to Ms. Freetly‘s electric utility operation proxies and lower credit ratings than her gas utility operation proxies. AIU asserts there would be no reason to conclude that, even with the riders, the equity market would view them as less risky than the proxies.

AIU argues Ms. Freetly‘s second approach presumes there is an expectation built into the proxy utilities‘ costs of equity, for when they systematically under-recover bad debt expense. AIU states there is no such expectation, and thus, there is no rationale for removing a premium that does not exist. AIU asserts Ms. Freetly did not look at the specific under- or over-recovery experience of the proxy utilities for the same ten-year period that she reviewed for AIU, therefore she can not know whether AIU faces greater risk; she only knows one side of the equation. AIU notes this second approach would also reduce the return for a risk for which AIU has never been compensated because, as historic evidence shows, risk is not symmetric and AIU has not historically earned more or less than the allowed return.

AIU opines that Ms. Freetly‘s downward adjustments for the uncollectible riders are effectively premised on the assumption that AIU has similar business risk to the proxy utilities before the adoption of the riders. AIU argues several factors – including regulatory lag and rising operating costs and capital expenditures – indicate AIU has higher business risk than the proxy companies. AIU avers that a relatively broad sample of gas and electric utilities has higher implied credit ratings on Moody‘s —regulatory framework" and —ability to recover costs and earn returns" factors than AIU, which suggests that Ms. Freetly‘s implicit point of departure for making her downward adjustments, similar business risk, is incorrect.

AIU states Ms. Freetly‘s approach is further flawed because her analyses of each of the AIUs‘ risk relative to each other, which are then applied to the sample group, arrive at disparate conclusions. AIU argues that the adjustment calculated by Ms. Freetly indicates that the reduction in risk would be higher for AmerenCILCO than for AmerenIP, indicating more uncollectible risk for AmerenCILCO. AIU points out however, that Ms. Freetly, based on her metrics applied relative to the sample group, indicated the two companies have the same indicated level of risk, which led her to recommend the same ROE for each. AIU argues the proposed adjustments are arbitrary and lack the precision needed to impact the Commission authorized rate or return on common equity. While Ms. Freetly denies that Moody's reflection of the bad debt rider legislation eliminates the need to adjust the costs of common equity of the gas and electric samples, AIU notes she provides no empirical evidence to support this assertion.

AIU argues that Staff's method of taking two estimates of the reduction in perceived investor risk is hopelessly flawed and offers false precision. By doing any calculation, Staff is suggesting that it can isolate the uncollectibles risk embedded in the ROEs produced by its analysis. To do this, Staff just takes two bad estimates and averages them, which AIU opines produces nonsensical results. Moreover, AIU avers that the two approaches she averages produce results so far apart that averaging offers no confidence that the resulting adjustment is reasonable. While Ms. Freetly acknowledged that she saw one method as being as likely as the other to be accurate, AIU submits that where one approach produces a result 16 times greater than the other approach, it is hard to say either is likely to be right. If the Commission concludes a downward adjustment is required, AIU suggests the Commission should simply adopt the 10 basis point adjustment it approved in the Peoples/North Shore dockets for each of the AIU companies.

2. Staff Position

a. Return on Equity Estimates

Ms. Freetly measured the investor-required Rate of return on common equity with the non-constant DCF and Capital Asset Pricing Model (―CAPM”) analyses. For AIU gas utilities, Ms. Freetly applied those models to the same sample of 9 local gas distribution companies utilized by AIU witness McShane. For the AIU electric utilities, Ms. Freetly began with Ms. McShane‘s sample of electric utilities but eliminated the electric companies the Edison Electric Institute categorized as ―Mostly Regulated” since her return on common equity recommendation is for the regulated electric operations of AIU. Ms. Freetly then eliminated the companies that were not assigned an industry classification code of 4911 or 4931 within S&P Utility Compustat. Then, Ms. Freetly removed companies that are, or recently have been, involved in mergers, acquisitions, or divestures. Finally, Ms. Freetly removed companies that lacked growth rate estimates from Zacks Investment Research (―Zacks”) or the data necessary to calculate beta. The remaining 16 regulated electric utilities compose Ms. Freetly‘s electric sample.

Staff states that a 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. Staff notes that since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that a stock price embodies, further noting that 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.

Ms. Freetly modeled three stages of dividend growth. The first, near-term growth stage is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year. The third or —steady-state" growth rate is assumed to begin after the tenth year and continue into perpetuity.

For the first stage, Ms. Freetly used market-consensus expected growth rates published by Zacks as of August 18, 2009. To estimate the long-term growth expectations for the third, steady-state stage, she utilized the implied 20-year forward U.S. Treasury rate in 10 years, 4.83%. The growth rate employed in the intervening, 5-year transitional stage equals the average of the Zacks growth rate and the steady-state growth rate. The growth rate estimates were combined with the closing stock prices and dividend data as of August 18, 2009. Based on these growth assumptions, stock price, and dividend data, Ms. Freetly's DCF estimate of the cost of common equity was 9.79% for the gas sample, and 10.67% for the electric sample.

Staff states that according to financial theory, the required ROR for a given security equals the risk-free ROR plus a risk premium associated with that security. Staff notes that the risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. Ms. Freetly used a one-factor risk premium model, the CAPM, to estimate the cost of common equity. In the CAPM, the risk factor is market risk, which can not be eliminated through portfolio diversification.

Staff avers that the CAPM requires the estimation of three parameters: beta, the risk-free rate, and the required ROR on the market. For the beta parameter, Ms. Freetly combined adjusted betas from Value Line, Zacks, and a regression analysis to estimate the beta of the gas and electric sample. For the gas sample, the average Value Line, Zacks, and regression beta estimates were 0.68, 0.56, and 0.51, respectively. For the electric sample, the average Value Line, Zacks, and regression beta estimates were 0.71, 0.72, and 0.66, respectively. The Value Line regression employs 260 weekly observations of stock return data regressed against the New York Stock Exchange (—NYSE") Composite Index. Both the regression beta and Zacks betas employ 60 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. Since the Zacks beta estimate and the regression beta estimate are calculated using monthly data rather than weekly data (as Value Line uses), Ms. Freetly averaged those results to avoid over-weighting betas estimated from monthly data in comparison to the weekly data-derived Value Line betas. She then averaged the resulting monthly beta with the Value Line weekly beta, which produced a beta of 0.61 for the gas sample and 0.70 for the electric sample.

Staff avers that for the risk-free rate parameter, Ms. Freetly considered the 0.14% yield on 4-week U.S. Treasury bills and the 4.40% yield on 30-year U.S.

Treasury bonds, with both estimates measured as of August 18, 2009. Forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.2%. Thus, Ms. Freetly concluded that the U.S. Treasury bond yield is currently the superior proxy for the long-term risk-free rate.

Staff opines that for the expected ROR 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 ROR on the market was 12.70% for the second quarter of 2009. Inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 9.46% for the gas sample and 10.21% for the electric sample.

Ms. Freetly estimated the investor-required rate of return on common equity for the gas sample of 9.63% by taking the simple average of the DCF-derived results (9.79%) and the risk-premium derived results (9.46%) for the gas sample. She then adjusted the gas sample's investor-required ROR downward by 15 basis points for AmerenCIPS to reflect the lower financial risk of AmerenCIPS relative to the gas sample. She also adjusted the gas sample's investor-required ROR upward by 10.5 basis points for AmerenCILCO and AmerenIP to reflect higher financial risk of AmerenCILCO and AmerenIP relative to the gas sample. Next, Ms. Freetly adjusted the companies' cost of equity downward by 10 basis points to reflect the reduction in risk associated with the recovery of a greater portion of fixed delivery services costs through the monthly customer charge, which was authorized in AIU's last rate cases, Docket Nos. 07-0585 et al. (Cons.). Staff therefore recommends that for the natural gas distribution operations of AIU, the investor-required rate of return on common equity is 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP.

To estimate the investor-required rate of return on common equity for the electric delivery service operations of AIU, Ms. Freetly first took the simple average of the DCF-derived results (10.67%) and the CAPM derived results (10.21%) for the electric sample, or 10.44%. Ms. Freetly then adjusted the electric sample's investor required ROR downward by 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS to reflect the lower financial risk of AmerenCILCO and AmerenCIPS relative to the electric sample. Thus, for the electric delivery service operations of the companies, the investor required rate of return on common equity is 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP.

Staff notes that AIU witness McShane estimated the cost of common equity using both the constant growth and non-constant growth DCF models and three equity risk premium analyses. Ms. McShane also applied the comparable earnings test for purposes of assessing the reasonableness of her results. Based on the updated analysis in Rebuttal Testimony, for the natural gas distribution operations, she recommended an 11.2% cost of common equity for AmerenCILCO and AmerenIP and a 10.8% cost of common equity for AmerenCIPS. For the electric delivery service operations, Ms. McShane recommended an 11.7% cost of common equity for AmerenCILCO and AmerenIP and an 11.3% cost of common equity for AmerenCIPS.

Staff asserts that Ms. McShane's analysis contains several errors that lead her to over-estimate AIU's cost of common equity. Staff argues the most significant flaws in Ms. McShane's analysis of the companies' cost of common equity are the use of historical data in her DCF and risk premium models; the inclusion of unwarranted adjustments to the DCF and risk premium results for alleged difference between market value and book value; and the inappropriate use of comparable earnings model as a check on her recommended cost of equity. Staff, therefore, recommends that the Commission reject AIU's recommended costs of common equity, and adopt Staff's recommendation, as stated above.

b. DCF and CAPM Model Issues

Staff argues that the use of historical data is problematic, as historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Staff further opines that historical data reflects conditions that may not continue in the future. Staff avers that the use of average historical data implies that securities data will revert to a mean, and while state there is no evidence securities data is mean reverting, there is also no method for determining the true value of that mean let alone the length of time over which mean reversion will occur.

Staff states Ms. McShane uses historical data in determining the dividend yield in her DCF model, however, since stock prices reflect all current information; only the most recent stock price can reflect the most recently available information. Staff asserts that historical stock prices must include observations that can not reflect the most current information available to the market.

While Ms. McShane implies that her use of historical data to estimate the dividend yield is an attempt to reduce measurement error, Staff asserts that introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Staff notes that 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 Ms. McShane already applies.

Staff notes that Ms. McShane performed an equity risk premium analysis, which calls for an estimate of the investor-required ROR on the market portfolio. Staff opines that to compute the achieved equity risk premium for her sample, she first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return, then calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return. Staff notes she also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.

Consequently, Staff argues Ms. McShane estimates the required ROR on the market using, in part, historical earned rates of return. Staff avers that as proxies for current required rates of return, historical earned returns possess several shortcomings, in that the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events. Staff further argues that even if an investment‘s return equaled investor requirements in a given period, both the price of, and the investment‘s sensitivity to, each source of risk changes over time. Further, Staff avers that the magnitude of the historical risk premium depends upon the measurement period used, therefore historical earned rates of return are questionable estimates of the required ROR that are susceptible to manipulation and whose use could distort the estimate of a company‘s cost of common equity. Staff notes the Commission has consistently rejected the use of historical dividend yields in calculating an appropriate ROE.

Ms. McShane argues that if the market value differs from book value, a cost of equity estimate derived from market values needs to be adjusted when applied to book values of common equity to determine utility rates. Staff argues that market to book adjustments such as Ms. McShane‘s are based on the flawed argument that a market-derived required ROR does not produce a ―fair" return when applied to a book value rate base if the market to book ratio differs from one. Staff avers that the crucial flaw in that argument is that it equates secondary investing (i.e., the purchase of existing shares of stock from other investors) with primary investing (i.e., the purchase of new shares of stock directly from the company or the retention of earnings for reinvestment). Staff notes the former does not affect the amount of money available to the company to buy assets because the proceeds from the sale go to the previous stockholder, not to the company. Staff argues that under original cost ratemaking, ratepayers provide a return only on the amount of capital that is invested in assets that serve ratepayers, and that inflating that return to compensate investors for capital not invested in plant and equipment is neither fair nor appropriate. While book value represents the funds a company receives from investors though security issuances on the primary market, Staff states that book value does not adjust to reflect changing investor assessments; it only reveals how much money the company has to invest in assets to serve its customers.

Staff notes that the market price is the price investors are willing to pay each other for a security on the secondary market. Staff avers that cost of common equity analysis uses market price data because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated. Staff states the market value of a stock would grow to exceed its book value only if investors expect to earn a return above their required return, and that the market price always reflects the investor-required return, regardless of the book value. Staff argues there is no merit to Ms. McShane‘s claim that her adjustment is required to recognize the higher return that equity investors require for bearing the higher financial risk inherent in AIU‘s proposed ratemaking capital structure in comparison to the market value capital structures of the gas and electric samples.

Staff submits that if a utility‘s services were entirely subject to original cost-based, ROR regulation and its rates perfectly and instantaneously reflected changes in its costs, then the market value of the firm would equal the book value whenever the expected ROR matches the investor required ROR. However, if the expected ROR exceeds the investor required ROR, Staff opines demand for the company‘s stock will increase as investors seek a share in those abnormally high returns, which will cause the stock‘s market value to rise until the expected ROR on market value equals the required ROR. Staff avers that the Commission should not further increase allowed rates of return when the benefits that utilities receive from other sources of earnings not recognized by the rate setting process increase stock prices above book value.

Staff further argues that allowing upward adjustments to the allowed ROR based on a market-to-book value ratio greater than one, would require the Commission to continually make upward adjustments to the allowed ROR, since such an upward adjustment would tend to again increase the market-to-book value ratio, thereby warranting another increase, resulting in a never ending upward movement in the allowed ROR.

While Ms. McShane argues that the lower book value common equity ratios of the companies relative to the gas and electric sample‘s market value common equity ratios indicate that the companies possess higher financial risk than the gas and electric samples, Staff opines that the intrinsic financial risk of a given company does not change simply because the manner in which it is measured has changed. Staff notes that capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Staff avers that Ms. McShane has previously proposed the same adjustment to her market-derived cost of equity estimates. In Docket Nos. 02-0798 et al. (Cons.), the Commission rejected her proposed market-to-book adjustment, noting that the Commission has a long history of applying its estimated market required rate of return on common equity to its book value, net original cost rate base for Illinois jurisdictional utilities. The Commission found that there was no evidence that this practice had served as an impediment to a utility‘s ability to raise capital or maintain its financial integrity. Ms. McShane's argument was similarly rejected in Docket Nos. 06-0070 et al. (Cons.).

Staff notes that Ms. McShane‘s comparable earnings model uses the average historical earned return on book value of common equity for a proxy group of 81 U.S. industrial companies over the period 1991-2007, claiming that her comparable earnings test indicates that competitive firms of similar risk to her sample of gas utilities may be expected to earn average returns of approximately 15.0% to 16.0%.

Staff opines that the comparable earnings methodology is based on the erroneous assumption that earned or expected returns on book equity are acceptable substitutes for investor-required returns. Staff avers that investor return requirements are a function of risk and manifested in the market prices of securities, while Ms. McShane‘s comparable earnings analysis is based on accounting returns, which are largely unresponsive to market forces. Staff argues that Ms. McShane herself acknowledges that the comparable earnings test does not measure the investor-required rate of ROE. Staff notes that the Commission has likewise repeatedly rejected the comparable earning methodology, finding that it is faulty as it incorrectly assumes that earned returns on book common equity are representative of investor required returns on common equity, referencing Docket Nos. 02-0798 et al. (Cons.) and Docket Nos. 06-0070 et al. (Cons).

Staff submits that both of the comparable earnings analysis in the prior cases cited above are based on earned returns on book equity as substitutes for investor required returns, while in this proceeding, Ms. McShane claims that the results of the comparable earnings test should be relied on as an indicator of whether her market-based test results (the DCF and equity risk premium), as adjusted for the market/book ratio are reasonable. Staff urges the Commission to once again disregard Ms. McShane‘s comparable earnings analysis.

c. Growth Rates

Staff notes that AIU insists that it is appropriate to include the results of the constant growth DCF analysis in the estimation of the investor required ROR for AIU, while in Staff‘s opinion, the three- to five-year growth rates for the companies in the Gas and Electric samples can not be sustained over the long-term.

While AIU notes that Staff did utilize a constant growth DCF to develop the expected return in the market in the risk premium model, Staff suggests its use of the constant growth DCF to estimate the return on the market does not support performing a constant growth DCF analysis on the gas and electric samples. Staff argues it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of attempting to apply the more elaborate non-constant growth DCF on 500 companies. Staff avers that as with the three- to five-year growth rates for some of the companies in the gas and electric samples, some of the growth rates used in Staff‘s DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff‘s market return estimate and, thus, in Staff‘s CAPM cost of equity estimate.

While Staff used the implied forward yield on 20-year U.S. Treasury bonds to estimate long-term overall economic growth during the steady state growth stage of the non-constant DCF analysis, AIU advocates using the Blue Chip forecast to estimate long-term economic growth. Staff states the Blue Chip forecast used by AIU to estimate long-term economic growth only projects forward 10 years, while the period for which the long-term growth rate is applied begins after 10 years. Staff argues the forecasts do not even overlap, much less coincide with, the period of time the steady-state growth stage covers.

While AIU points to the recent swings in the implied 20-year forward U.S. Treasury yield in comparison to the virtually unchanged consensus forecasts of long-term economic growth, Staff states the changes in the U.S. Treasury yield indicate that investor‘s current long-term expectations vary over time, while AIU's argument implies that investors' expectations of the long-term economic growth are essentially static. Since the yield on U.S. Treasury bonds reflects changing investor expectations due to current economic conditions, Staff submits it is a timely gauge of the expected long-term economic growth. In contrast, Staff argues as the long-term forecasts AIU relies on are not updated regularly, the alleged stability in the Blue Chip forecasts of long-term economic growth might come from a low update frequency.

While AIU notes that Staff's use of the non-constant DCF is a departure from Staff's typical use of the constant growth DCF, pointing out that Staff relied on the constant growth DCF model in previous testimony when analysts' consensus forecasts were higher than the forecast long-term growth in the economy, Staff states AIU's argument implies that Staff can not modify its methodology even when a revised methodology more accurately reflects existing circumstances, and is likely to yield more reliable results.

Staff notes that Ms. Freetly testified that a single-stage constant growth DCF model employs a single growth rate estimate, which is assumed to be sustainable infinitely. Staff argues a cost of common equity calculation derived from a constant growth estimate is correct only if the near-term growth rate forecast for each company in the sample is expected to equal its average long-term dividend growth, as no company could sustain into infinity a growth rate any greater than that of the overall economy. Staff states that given the difference between the growth rates for the gas and electric samples and the overall growth of the economy, the continuous sustainability of the analyst growth rates for the gas and electric samples is highly unlikely.

Staff agues that inclusion of the constant growth DCF analysis can not be reconciled with the compelling rationale for employing the non-constant DCF analysis, namely that the three- to five-year analyst growth rates are unsustainable, noting the decision as to which model to employ must be consistent with the judgment regarding the sustainability of the growth rate to be used in the model.

While AIU states that Staff's long-term growth rate used in the final stage of the non-constant DCF analysis based on the implied 20-year forward U.S. Treasury rate is inferior to the estimate of long-term economic growth provided by the consensus of economists' forecasts published by Blue Chip, Staff avers that AIU ignores Ms. Freetly's Testimony that she compared her 4.83% U.S. Treasury bond-derived estimate of long-term growth against the 4.5% forecast of Global Insight. While Staff agrees that with the use of a consensus forecast of long-term economic growth for a period that begins 10 years from now, the record contains nothing to suggest that any exists, noting the Blue Chip forecast that AIU espouses covers a period that ends 10 years into the future.

Staff submits that AIU's argument concerning the alleged stable nature of long-term growth forecasts aims at one target, Staff's long-term growth estimate, but hits another, the constant growth DCF. Staff notes that the constant growth DCF assumes that short-term growth equals long-term growth, and therefore the growth rates used in the constant growth DCF should be stable. Staff submits the evidence proves that the growth rates Ms. McShane uses in her constant growth DCF analysis are anything but. In the last rate case proceedings for AIU, Docket Nos. 07-0585 et al. (Cons.), Staff avers that Ms. McShane's constant growth DCF analysis used Institutional Brokers' Estimate System ("IBES") growth rate forecasts, with the IBES growth rate for the gas companies common to the 2007 and current cases averaged 4.6%. Staff notes that in the current proceeding, the IBES growth rate for the gas utilities in common to the 2007 and current cases averaged 5.7%. Staff submits that many of the electric companies common to the 2007 and current cases also exhibit some large differences in the IBES growth rate forecasts, with 13 of the 24 electric companies that were part of the electric sample in both 2007 and 2009 changing by more than two percentage points. Staff argues that those large differences indicate the IBES growth rates are not stable, which, according to AIU, disqualifies the IBES growth rates from being considered as long-term growth rates. Staff states that since the IBES growth rates can not be used as long-term growth rates, they can not be used in a constant-growth DCF model, and, therefore, the results of the constant growth DCF should not be considered in determining the investor required rate of return on common equity for setting rates in this proceeding.

Staff avers there is no valid justification for disregarding the investor expectations imbedded in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections. Staff states it is important to note that U.S. Treasury bond yields directly reflect the expectations of investors, while Blue Chip forecasts do not. Staff argues the forecasts Ms. McShane advocates are merely proxies for investor expectations, and that proxies should be used only when the market factor in question is not observable. Staff states that since market expectations for U.S. Treasury bond yields are observable, proxies for those expectations, such as a Blue Chip forecast, should not be used.

Staff further notes that the Blue Chip Financial Forecasts relied on by Ms. McShane to estimate the long-term economic growth reveals that the forecast did not include the recessionary period in 2009 and 2010, and submits that when using a forecasted growth rate for the economy, the whole business cycle must be included in order to get a measure of the normal steady state rate of growth that can reasonably be expected over the long term.

d. Beta

Staff proposes to use regression betas in this proceeding, while AIU proposes to use Value Line betas. While AIU complains that regression betas have been consistently lower than Value Line betas, Staff notes this argument does not provide insight into which beta estimation procedure is superior. Staff opines that Value Line, Zacks, and regression betas are estimates of the unobservable true beta, which measures investors' expectations of the quantity of non-diversifiable risk inherent in a security. Staff avers that different beta estimation methodologies can produce different betas when those methodologies employ different samples of stock return data. Staff submits that its methodology used to calculate the regression betas for the gas sample, which Staff has regularly used and the Commission has consistently approved, employs the same monthly frequency of stock price data as the widely accepted Merrill Lynch methodology. Staff states further that Ms. McShane's argument to exclude Staff calculated betas and rely upon only Value Line betas was rejected by the Commission in Docket No. 00-0340.

Staff avers that while Ms. McShane presented an analysis comparing weekly and monthly betas to support her conclusion that weekly betas are to be preferred, the statistics that she presents do not compare the —superiority" of the parameter estimates, but rather they test the predictive ability of the model. Staff argues that to test the predictive accuracy of different betas, the beta estimate has to be the independent variable, while in Ms. McShane's analysis, beta is the parameter estimate. Staff opines her test simply indicates how much the variation in the market return explains the variation in the return of the stock, but does not support the conclusion that monthly betas are statistically inferior to weekly betas. Staff notes that Ms. McShane did not provide any academic support for her conclusion that weekly betas are superior to monthly betas. Staff avers that in response to Staff DR JF 6.04, AIU stated that Ms. McShane was not aware of any studies that have addressed whether weekly betas are more accurate predictors of future utility stock performance than monthly betas.

In contrast, Staff cites two studies that compared weekly and monthly beta estimates but neither concluded that either beta was superior. Staff opines that those studies found a relatively weak relationship between Value Line and Merrill Lynch betas and showed that the major cause of the significant differences in beta was the use of monthly versus weekly return intervals. Staff argues that the difference in beta estimates may be the effect of non-synchronous trading, which occurs when the market return reflects information that is not yet reflected in the stock's return.

Staff notes it investigated whether non-synchronous trading was a problem for weekly or monthly betas. Staff avers that to account for the lag in stock price reaction to economic events that affect the market, security returns can be regressed against the returns of the market in the current period as well as the returns of the market in prior periods, with the coefficients for the current and lagged regressions summed together to derive a beta estimate. Staff argues it calculated Ms. McShane's weekly regression betas with three lags, with the security returns of the gas sample lagging behind the market data by one, two and three weeks. Staff notes the one and two week lags, which are -0.07 and -0.11, respectively, are statistically different from zero, which indicates that non-synchronous trading is a problem with Ms. McShane's weekly data. Staff also calculated the lag beta for the monthly regression beta for the gas sample that Staff proposed. Staff avers the lag beta was not significantly different from zero, which indicates that non-synchronous trading was not a problem when using monthly data.

While Ms. McShane speculated that the results might relate to the market conditions during the financial crisis since the same analysis conducted for the periods ending 2005 and 2006 produces different results, Staff states that its lag beta analysis used the same five-year time period as Ms. Freetly's CAPM analysis to estimate the investor-required ROR. Staff opines it is the relevant time period to examine to determine whether non-synchronous trading affected the data Ms. Freetly used to calculate beta.

Further, Staff compared the coefficient of variation using Ms. McShane's weekly and monthly data, noting the coefficient of variation was higher for weekly data. Staff states although the higher number of observations of the weekly data increases the degrees of freedom, and hence narrows confidence intervals, it also increases the magnitude of the variation relative to the mean of the sample stock returns, which leads to an increase in random error.

Staff opines that weekly and monthly betas have strengths and weaknesses relative to each other. Staff states that Ms. McShane's analysis shows the standard error of weekly beta estimates is generally lower than those for monthly beta estimates, indicating that weekly betas are usually more reliable, or have lower variation in the beta estimate than monthly betas. Conversely, Staff avers that monthly betas are less susceptible to non-synchronous trading than weekly betas. Staff argues monthly betas are calculated from returns that have lower coefficients of variation than weekly betas, which indicates that the monthly betas are more accurate than weekly betas. Since neither type of beta is clearly superior to the other, Staff recommends the Commission equally weight weekly and monthly betas in determining a cost of common equity with the CAPM.

e. Market Risk Premium

While Ms. McShane states that a —spot" yield should not be relied upon as representative of expected yields and used as the risk-free rate in the CAPM, Staff avers that the current U.S. Treasury yields that Staff used to estimate the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. Staff argues that investor appraisals of the value of forecasts are reflected in current interest rates, therefore, if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. As interest rates are constantly adjusting and accurately forecasting the movements of interest rates is problematic, Staff urges the Commission to continue to rely on current, observable interest rates rather than the forecasted rates supported by Ms. McShane.

Although AIU maintains that the —spot" interest rates are not appropriate for application of the CAPM since a forward looking estimate of the cost of equity should recognize the high probability that U.S. Treasury yields will increase, Staff argues the current U.S. Treasury yields that Staff used as the risk-free rate reflect all relevant, currently available information, including investor expectations regarding future interest rates. Staff avers that as of August 18, 2009, investors were willing to accept a 4.40% return on U.S. Treasury bonds. Staff states there is no valid justification for disregarding the investor expectations directly reflected in objective, observable current market data in favor of a proxy for those expectations imbedded in speculative projections.

Staff notes that AIU chose to initiate this proceeding during a severe economic recession when it appears a large segment of its customer base is suffering financially, and during economic downturn, interest rates have fallen. Staff's recommended cost of common equity reflects that economic reality, while AIU would have the Commission reward AIU's decision to file a rate case during a severe economic recession with a rate increase that assumes that AIU filed its requested rate increase during a far more favorable economic environment.

IIEC argues that Staff's market risk premium in its CAPM analysis is overstated, Staff recognizes that some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate, and, thus in Staff's CAPM cost of equity estimate. Staff avers that while there is upward bias in Staff's estimate of the market return, there is no way to know the extent of the bias. Staff notes it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate model to 500 companies. Staff states Mr. Gorman's non-constant DCF analysis of the S&P 500 illustrates the difficulty of applying that model to the diverse group of companies that compose that index, as his estimate of the required return of the market is 8.71%, 129 basis points below his 10.00% rate of return on common equity recommendation for AIU. Staff asserts his results imply that the S&P 500 is less risky than AIU, which is not plausible.

f. Proposed Adjustments

(1) Financial Risk

Staff states that based on a simple average of her DCF and risk premium analyses, Ms. Freetly estimated that the investor-required rate of return on common equity is 9.63% for the gas sample and 10.44% for the electric sample, which are proxies for the gas and electric operations of AIU. Staff avers if the proxy does not accurately reflect the risk level of the target company, an adjustment should be made.

To estimate the financial risk of AIU going forward, Ms. Freetly compared the financial strength implicit in Staff's proposed revenue requirement for each company's gas and electric operations to Moody's guidelines for the regulated gas and electric utilities, focusing on four ratios: (1) Funds From Operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow to total debt coverage; and (4) debt to capitalization.

Staff states that Ms. Freetly concluded that Staff's revenue requirement recommendations, including Staff's cost of common equity recommendations, indicate levels of financial strength that are commensurate with a Baa3 credit rating for AmerenCILCO gas, an A3 credit rating for AmerenCIPS gas and a Baa3 credit rating for AmerenIP gas.

In contrast, Ms. Freetly notes the gas sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa1, which is consistent with the current average credit ratings Moody's has assigned the gas sample, indicating the gas sample's level of financial strength indicates that it has more financial risk than the gas operations of AmerenCIPS and less financial risk than the natural gas distribution operations of AmerenCILCO and AmerenIP. Given the difference between the credit rating commensurate with the forward-looking financial strength of AIU's gas distribution operations and the credit rating commensurate with the financial strength of the gas sample, Staff asserts the sample's average cost of common equity needs to be adjusted to determine the final estimate of AIU's cost of common equity.

Staff states that 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 AIU and those of the gas sample. Staff opines the spread between the implied ratings of A3 for AmerenCIPS and Baa1 for the gas sample is 50 basis points, while the spread between the implied ratings of Baa3 for AmerenCILCO and AmerenIP and Baa1 for the gas sample is 35 basis points. Staff notes to determine the cost of equity adjustment, Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities. Staff therefore recommends a financial risk adjustment to the cost of equity for the gas operations of an increase of 10.5 basis points for AmerenCILCO and AmerenIP and a decrease of 15 basis points for AmerenCIPS.

Using the updated Moody's financial guideline ratios for electric utilities, along with AIU electric utilities' scores on those financial ratios, Staff submits Ms. Freetly concludes that Staff's revenue requirement recommendations, including Staff's cost of equity recommendations, indicate a level of financial strength that is commensurate with a Baa1 credit rating for AmerenCILCO, an Aa3 credit rating for AmerenCIPS, and a Baa2 credit rating for AmerenIP. In contrast, the electric sample's average financial ratios for 2006-2008 are indicative of a level of financial strength that is commensurate with a credit rating of Baa2, which Staff states is consistent with the current average credit ratings Moody's has assigned the electric sample. Staff argues the electric sample's level of financial strength indicates that it has more financial risk than the electric delivery service operations of AmerenCILCO and AmerenCIPS, therefore the sample's average cost of common equity needs to be adjusted to determine the final estimate of the cost of common equity.

Staff states that 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 AIU and those of the electric sample. Staff submits the spread between the implied ratings of Baa1 for AmerenCILCO and Baa2 for the electric sample is 20 basis points, while the spread between the implied ratings of Aa3 for AmerenCIPS and Baa2 for the electric sample is 100 basis points. To determine the cost of equity adjustment, Staff notes Ms. Freetly then multiplied those yield spreads by 30%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios under the new rating methodology for regulated gas and electric utilities, therefore Staff's financial risk adjustment to the cost of equity for the electric operations is a decrease of 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS.

Staff and AIU agree that when a utility has more or less financial risk than the sample companies used to estimate the cost of equity, an adjustment to the cost of equity is necessary. Ms. McShane asserts that when the market value common equity ratio is higher than the book value common equity ratio, the market is attributing less financial risk to the companies than the book value capital structure suggests. Staff states she claims that since the investor required ROR is estimated based on the market value of the companies in the gas and electric samples, adjustments to recognize the higher financial risk implied by the book value capital structure of AIU is required.

Staff maintains that there is no merit to Ms. McShane's claim, arguing the fundamental problem with Ms. McShane's claim is that it assumes, without foundation, that the book value capital structure of AIU directly reflects investors' perceptions of the financial risk of AIU. Staff opines that while investors are unlikely to ignore the book value capital structure of companies generally and utilities specifically, investors' perceptions of AIU's financial risk inherent in its book value capital structure are not observable because its common stock is not market traded.

Staff states its recommendations reflect the revenue requirements necessary to set just and reasonable rates, which will remain in effect until a future rate proceeding. While Ms. Freetly used Staff's recommendations to estimate the credit metrics that may be achieved with the rates set in this proceeding, Staff's analysis of the implied level of financial strength of the gas and electric utility operations of each of the AIU is not an attempt to predict the rating outcome of Staff's position in these rate proceedings. Staff claims it did not attempt to determine its own credit ratings for AIU nor is Staff suggesting that simply because AIU's metrics fall within the guideline ranges that the implied ratings will result. Staff asserts it performed the ratio analysis in order to compare the financial strength of AIU, based on the FFO to interest coverage, FFO to total debt, DCF to total debt coverage and debt to capitalization, to those of the gas and electric samples. Staff opines the resulting ratios were translated into implied credit ratings only to have a metric on which to base an adjustment to the cost of equity.

Staff avers it did not use the current credit ratings of AmerenCILCO, AmerenCIPS and AmerenIP for comparison to the gas and electric samples for several reasons. Staff claims credit ratings reflect the risk of a company's entire operations, not just those operations subject to the Commission's rate jurisdiction. Further, Staff states credit ratings also reflect a company's affiliation with other companies, while Section 9-230 of the Act prohibits including in a utility's allowed ROR any incremental risk or increased cost of capital which is the direct or indirect result of a public utility's affiliation with unregulated or nonutility companies. Third, Staff asserts credit ratings reflect the credit ratings agency's forecast, and since those forecasts are not published, they can not be compared to Staff's revenue requirement recommendations. Staff states that based on this, AIU's credit ratings should not be relied upon absent an investigation of the underlying stand-alone, going forward strength of AIU.

Staff notes AIU claims that Staff's financial risk adjustment incorrectly assumes that equity investors quantify financial risk differences in the same manner as bond investors. Although Staff agrees that bond and common equity investors would not likely apply the same price to a given difference in financial risk, since Staff notes the price the latter would attach to financial risk can not be observed, a proxy is necessary. Staff claims the bond yield spreads that Staff's adjustment is based on are the best estimate of the different return requirements that investors would demand for varying levels of financial risk. Staff asserts it is an objective measure of the return equity investors would require to invest in AIU given the different levels of financial risk indicated by Staff's ratio analysis.

(2) Fixed Customer Charge

Staff notes the Commission authorized the AIU gas utilities to recover 80% of the fixed delivery service costs through the monthly customer charge in the last rate cases, which cost recovery method will remain in effect when the rates set in this proceeding go into effect. Staff asserts in AIU's last rate cases, the Commission recognized that this move toward more fixed cost recovery through the fixed monthly charge provides the AIU gas utilities more assurance of recovering its fixed costs of service for gas operations, reducing risk and providing the utilities greater assurance that the authorized ROR will be earned. Ms. Freetly's cost of common equity recommendation therefore includes the same 10 basis point adjustment to the cost of common equity for the AIU gas companies that the Commission found appropriate in the last rate cases to reflect the reduction in risk provided by this method of cost recovery.

While Ms. McShane claims that eight of the nine gas distributors in the Gas sample have similar mechanisms in place and therefore, the cost of common equity estimate for the gas sample already reflects the risk reduction, Staff states most of the companies in the gas sample have in place some sort of de-coupling mechanism, some of those mechanisms are only applicable to a portion of the company's service territories, and one of the companies has no de-coupling mechanism at all. Staff opines that a small cost of equity adjustment for the reduction in risk provided by this method of cost recovery is warranted, and the 10 basis point downward adjustment adopted in AIU's last rate case is appropriate in this proceeding.

(3) Uncollectibles Riders

Staff asserts its cost of equity recommendations do not take into account any change in risk associated with the new uncollectibles riders AIU approved in Docket No. 09-0399, therefore, Staff recommends further adjustment to the cost of common equity for the uncollectibles riders authorized by the Commission.

Staff argues the uncollectibles riders approved in Docket No. 09-0399 ensure more timely and certain collection of bad debt expense, which provides greater assurance that the Companies will earn their authorized rates of return. Staff states that since the uncollectible riders would reduce uncertainty of cash flows, it would reduce risk, and therefore, downward adjustments to AIU's rates of return on common equity would be appropriate to recognize the reduction in risk associated with the use of the uncollectibles riders.

Staff notes that Moody‘s recently upgraded the ratings of the AIUs to investment grade reflecting reflects positive developments in Illinois, including the recently passed legislation providing Illinois utilities with a bad debt rider. Staff avers that Moody‘s acknowledges that such riders would reduce the risk of the utilities by providing greater assurance of bad debt cost recovery and factored that into the decision to upgrade the AIUs to investment grade.

Staff states it is unaware of any established approach for precisely gauging the effect the adoption of the uncollectibles riders would have on investors‘ perceptions of AIU's risk levels and the resulting costs of equity, therefore any adjustment will inevitably be inexact. Therefore, Staff‘s proposed adjustments for Riders GUA and EUA reflect a range of alternatives using two distinct approaches.

In the first approach, Staff estimated the effect the adoption of Riders GUA and EUA would have on AIU's Moody's credit ratings and based the adjustment of the resulting change in the implied yield spreads. Staff states Moody‘s updated rating methodology for regulated electric and gas utilities focuses on four core rating factors: regulatory framework, ability to recover costs and earn returns, diversification, and financial strength and liquidity.

Staff avers that of the four updated rating factors, the adoption of an uncollectibles rider would affect the utilities‘ ability to recover costs and earn returns, which factor assesses the ability of the utility to recover prudently incurred costs in a timely manner. For local gas distribution companies in the United States, Staff opines this factor addresses the sustainable profitability and regulatory support assessments in the previous methodology. Staff argues a utility‘s score on this factor would improve with implementation of an uncollectibles rider that allows timely adjustment of rates to cover uncollectible costs since its ability to earn its authorized ROR would be enhanced, and notes Moody‘s assigns a 25% weighting to this factor.

Staff assumed that the credit rating assigned to this factor would improve by one credit rating (3 points on the numeric scale) with the implementation of the uncollectibles rider, which would raise the score for this factor by 3 rating points, and result in an improvement to the Companies‘ overall credit ratings of approximately one credit rating notch.

Staff asserts that for the natural gas distribution operations, this analysis indicates that the going forward level of financial strength is consistent with credit ratings which would change from Baa3 to Baa2 for AmerenCILCO and AmerenIP and from A3 to A2 for AmerenCIPS. Staff opines the returns on common equity would be reduced by the 15 basis point spread between credit ratings of Baa3 and Baa2 for AmerenCILCO and AmerenIP, and by the 10 basis point spread between credit ratings of A3 and A2 for AmerenCIPS.

For the electric delivery service operations, Staff argues its analysis indicates that the going forward level of financial strength is consistent with credit ratings which would go from Baa1 to A3 for AmerenCILCO, Aa3 to Aa2 for AmerenCIPS, and from Baa2 to Baa1for AmerenIP. Staff argues the returns on common equity should therefore be reduced by the 50 basis point spread between credit ratings of Baa1 and A3 for AmerenCILCO, the 10 basis point spread between credit ratings of Aa3 and Aa2 for AmerenCIPS, and by the 20 basis point spread between credit ratings of Baa2 and Baa1 for AmerenIP.

Staff states the second approach is an iterative process of adjusting Staff's cost of common equity estimate downward to offset the increased operating income resulting from the adoption of Rider GUA in Docket No. 09-0399 (hereafter, ―Operating Income Analysis"). Based on Staff's pre-adjustment ROR recommendations of 9.64% for AmerenCILCO gas and AmerenIP gas and 9.38% for AmerenCIPS gas and Staff's rate base recommendations of $190,360,000 for AmerenCILCO gas, $193,701,000 for AmerenCIPS gas, and $511,117,000 for AmerenIP gas, Ms. Freetly calculated pro forma operating incomes without Rider GUA (Staff's rate base x ROR recommendations) of $15,135,546 for CILCO gas, $14,884,141 for CIPS gas and $44,473,038 for IP gas. To estimate the effect Rider GUA would have on the pro forma operating income of each of the AIU gas utilities, Staff avers that Ms. Freetly subtracted the companies' estimates of uncollectibles recovery via base rates from the Account 904 balances for the years 1999-2008, dividing the average difference between the companies' estimates of uncollectibles recovery via base rates and Account 904 balances over the last 10 years by the pro forma operating income without Rider GUA. If Rider GUA had been in effect during the last 10 years, Staff's analysis indicates if Rider GUA had been in effect during the last 10 years, the pro forma operating incomes for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP would have been approximately 9.61%, 10.35%, and 5.60% higher, on average. Ms. Freetly then multiplied the pro forma operating incomes for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP by those respective amounts to estimate the effective pro forma operating incomes if Rider GUA were adopted but no adjustments were made. Staff states Ms. Freetly then adjusted her cost of common equity downward until the pro forma operating incomes under Rider GUA equaled the original pro forma operating incomes Staff calculated for the companies without Rider GUA. Staff opines this process produced downward adjustments to the costs of equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 160, 149, and 106 basis points, respectively, to reflect the risk reduction associated with Rider GUA.

Staff states it performed the same calculation regarding AIU's electric operations, additionally performing various calculations involving Staff's pre-adjustment ROR recommendations for AIU, along with the ratio of average Account 904 balances to pro forma operating income for each AIU. Staff in its Initial Brief (―IB") discusses the exact formula it used to estimate the operating income for each company if the respective uncollectible rider had been in effect. (Staff IB at 137-140) Staff asserts that this process produced downward adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 76, 119, and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

While AIU Nelson criticizes Staff's recommendation to adjust the ROR downward to reflect the reduced risk from adoption of the uncollectibles rider, claiming there should be zero impact on the ROE; Staff claims this is contrary to financial theory on the trade off between risk and return. Staff claims the increased certainty of uncollectibles cost recovery by adoption of the riders results in a reduction in risk and, thereby, warrants a reduction to the cost of common equity, as the adopted riders remove uncertainty associated with the recovery of uncollectible expense.

Although Mr. Nelson claims that the riders provide reciprocal benefits to shareholders and ratepayers, Staff avers the uncollectibles riders shift the risk of under recovery of uncollectibles expense from investors to the customers who pay their bills, in essence requiring ratepayers who pay their bills to provide a guarantee to AIU that all of its uncollectibles expense will be recovered. Staff notes that if ratepayers are compensated for the guarantee that they will provide, Mr. Nelson would be correct that ratepayers would get a benefit from providing this guarantee to AIU and its investors; however AIU seeks to deny ratepayers that compensation.

AIU's claim that Staff's proposed adjustment to the ROE is an indirect approach to ensure that AIU continues to under recover uncollectibles and is punitive in nature ignores, Staff opines, that the uncollectible riders guarantee AIU recovery of uncollectible expenses, thereby reducing the uncertainty of cost recovery. Staff notes that guarantees have costs in the financial markets, and as AIU is asking its customers to guarantee the recovery of uncollectible expenses through the rider mechanism, AIU ratepayers should be compensated for providing that guarantee.

Staff opines that basing the magnitude of the ROR adjustment on the amount of uncollectibles is appropriate not only because the amount of risk that is shifted from investors to ratepayers is related to the amount of uncollectibles, but it also provides AIU with a financial incentive to reduce uncollectibles. Staff states the lower the amount of uncollectibles, the lower the downward adjustment to the ROR related to Riders GUA and EUA.

While AIU states that Moody's was aware of the passage of this rider prior to its recent upgrade of AIU's credit ratings and no further upgrade could be expected, Staff claims Moody's upgrade to AIU's credit ratings directly affects the cost of AIU's credit facilities and will affect the cost of future debt issues. Staff avers that upgrade does not affect the starting point for analysis of AIU's costs of common equity: the costs of common equity of the gas and electric samples. Staff notes it used the effect of the riders on credit ratings as one proxy of the effect of the riders on cost of common equity.

Staff states that AIU's comparison of Staff's financial risk adjustment and Staff's adjustment for the uncollectibles riders is not valid. Staff avers that the uncollectibles rider adjustment affects operating risk, not financial risk. Staff notes the operating income analysis recognizes the effect of the adoption of the uncollectibles riders and is based on the under-recovery experienced by each of the Companies over the last 10 years. The uncollectibles data shows that the affect of Rider GUA on AmerenCILCO gas would be greater than AmerenIP gas given the fact that uncollectibles is a much higher percentage of AmerenCILCO gas' operating income.

Staff notes that the results of its two analyses of the effects of the uncollectible riders range from 15 to 160 basis points for AmerenCILCO gas operations, 10 to 149 basis points for AmerenCIPS gas and 15 to 106 basis points for AmerenIP gas. Based on the midpoints of those ranges, Staff recommends adjustments to the costs of common equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 87.5, 79.5, and 60.5 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider GUA. Staff states the results of this calculations range from 50 to 76 basis points for AmerenCILCO electric, 10 to 119 basis points for AmerenCIPS electric, and 20 to 48 basis points for AmerenIP electric. Staff recommends using the midpoints of those ranges, with adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of 63, 64.5, and 34 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider EUA.

3. AG/CUB Position

a. Return on Equity Estimates

AG/CUB states that the Commission's task is to ensure that the cost of equity capital used to develop rates compensates investors for their investment risk, while assuring that customers do not pay an excessive or unreasonable return in those rates. AG/CUB avers that this is a decision made by weighing the relative riskiness of the regulated company against the relative riskiness of other investments, a task complicated by the fact that a "fair" return changes over time as the debt and equity markets change. AG/CUB notes that in the past two years, the relevant market changes include a fall in stock prices (as measured by the S&P 500) of more than 50% from the fall of 2007 through March 2009.

AG/CUB suggests that the problem with using the DCF and CAPM with the inputs AIU proposes is that the limited credit availability that has been endemic of the crisis has been caused by uncertainty in market fundamentals. AG/CUB submits that as the financial crisis has made clear, financial information from typical financial industry sources, such as rating agencies, can be dramatically wrong and strongly biased.

AG/CUB argues that the financial climate requires the Commission to return to basics instead of simply repeating past approaches that ignore very different market circumstances. AG/CUB notes that while CUB witness Thomas uses the same DCF and CAPM models, he adjusts the models, as well as the data inputs used in the models, to reflect the credit crisis and resulting discontinuity in the financial markets.

AG/CUB argues that AIU's analysis of the appropriate ROE is flawed because it incorporates overstated estimates of company growth and overstates the degree to which utility stock prices correlate to market prices, both of which increase AIU's proposed cost of equity estimate. While Ms. McShane proposes to increase these estimates further, producing different returns for each operating subsidiary based on the mistaken notion that the Commission should adjust returns to reflect the divergence of market and book values, AG/CUB opines that this results in inflated and unsupportable results. AG/CUB also notes that Ms. McShane advocates a comparable earnings test which has been rejected by the Commission in recent cases.

While AIU argues the Commission should reject Mr. Thomas' cost of common equity because it is not comparable to any cost of equity or return granted by other regulators, AG/CUB notes that the Commission has rejected such arguments in the past, noting each company must show that its proposed ROE is just and reasonable. AG/CUB argues that instead of rejecting Mr. Thomas' results because AIU finds them to be lower than any reasonable indicator of the returns investors expect, the Commission should base its order on the entirety of the record evidence, including the reasonableness of the analysts' various models and the inputs and assumptions. AG/CUB notes that the Commission has historically used the DCF and CAPM models, however Mr. Thomas testified that real world investors use very different techniques to determine the true cost of equity capital.

AG/CUB states that all parties have observed that the economic recession that began in 2008 has produced a very different economic climate than that of times past. AG/CUB argues that financial information from typical financial industry sources, such as rating agencies, can be dramatically wrong and strongly biased, and opines that the use of DCF and CAPM, both of which has been relied upon by the financial markets for a number of years, have proven to be unreliable in estimating an appropriate ROE.

AG/CUB further urges the Commission to reject AIU's proposed financial risk adjustment, noting that the Commission applies a market-determined ROR to the book value of the capital structure, and AIU presents no evidence that a change from this practice is required. AG/CUB opines that adjusting market-based DCF results before applying them to the book value of assets in rate base inflates the market-based cost of equity.

AG/CUB further supports the proposal by Ms. Freetly to adjust the AIU gas utilities' rate of return on common equity downward by 10 basis points, and continues to support her proposed adjustment to account for the presence of the AIU uncollectibles riders. AG/CUB avers that such an approach is reasonable in the event the riders are implemented. AG/CUB therefore recommends a return on common equity for AmerenCILCO's gas and electric operation of 6.92% and 8.35%; AmerenCIPS' gas and electric operation of 7.13% and 8.09%; and AmerenIP's gas and electric operation of 7.12% and 8.47%, respectively.

b. DCF and CAPM Model Issues

AG/CUB notes that the DCF model estimates the cost of equity capital by assuming that investors who purchase stock are paying a price that reflects the present value of the cash flows they expect to receive from the stock in the future. AG/CUB avers that using information about the current stock price and expected future cash flows from dividend payments and earnings growth, the model, which is based on the relationships among various factors, estimates the return that investors expect to receive on their investment.

AG/CUB submits that the actual return required to induce investors to make a particular investment is not a directly observable number because investors' requirements for future dividends and rates of growth can not be found in the pages of the Wall Street Journal and plugged into the model. AG/CUB states that in this case, the analysis is further complicated by the current market upheaval and by the fact that AIU does not have publicly traded stock, which would provide current, objective dividend and price information. AG/CUB opines that instead, proxy groups of companies are used to estimate the investor-perceived level of risk associated with a company such as the AIU and make projections of AIU's future growth. AG/CUB states the fundamental difference between AG/CUB and AIU's analysis lies in what is used to project AIU's future growth.

AG/CUB opines that the CAPM is an alternative analytical tool commonly used in regulatory proceedings to estimate investors' required ROR, or the cost of equity capital for the firm. AG/CUB states that for a utility, the investors' required ROR is the risk-free rate plus the value of the non-diversifiable risk that investors take on by investing in the utility. AG/CUB avers that the amount of that non-diversifiable risk that investors are exposed to through their investment in a particular firm's shares is measured by a beta coefficient.

AG/CUB notes that the key assumptions of the CAPM are that (1) in the market, investors are compensated only for non-diversifiable risk, quantifiable as a uniform EMRP, and (2) beta is an accurate measure of the relative risk of an individual security when compared with the overall market. AG/CUB states that CAPM is generally best employed as a check of the DCF model, arguing there are several well-known problems with both the theory and practical application of the CAPM. AG/CUB opines that even in that limited role, the Commission must recognize the deficiencies of the CAPM, require appropriate inputs, and use the results judiciously. AG/CUB asserts that the CAPM analysis presented by Ms. McShane has both an inappropriate adjustment of the beta parameter, and a grossly overstated EMRP.

c. Growth Rates

AG/CUB notes that the growth rate component of a DCF model represents the sustainable growth that investors expect in their investment due to expected increases in a company's earnings, which growth rate must be consistent with, and supported by, the economic conditions and dividend payout policies expected to occur. AG/CUB argues that in this environment, investors are focused on short-term changes in the equity markets, and as a result, both forecasted and historical growth rate information become highly subjective measures of expected future growth for individual firms. AG/CUB avers that while it is difficult to predict with accuracy a sustainable constant growth rate for companies, expectations of long-term growth in the U.S. economy are reasonable, and can be measured by the historic growth in real gross domestic product.

AG/CUB urges the Commission to use the following three basic criteria to evaluate projections of company growth earnings: (1) growth rate inputs must be reasonable in light of anticipated growth in GDP; (2) the long-term growth rate must not implicitly require continued earnings above the regulated firm's cost of equity, as derived in the analysis; and (3) the long-term growth rates must not require dividend payout ratios that are not consistent with the capital expenditure growth rate and the ROE.

AG/CUB submits that current analysts' standard three- to five-year growth projections do not meet these tests, something the financial literature has examined in recent years. AG/CUB opines that many researchers have found that analysts tend to be optimistic about future growth and produce forecasts that are upwardly biased, which translates into DCF cost-of-capital estimates that are above the true required cost of capital.

Ms. McShane argues that various studies have concluded analyst forecasts are a better predictor of growth rates than historic growth estimates. In support of her contention, AG/CUB notes that Ms. McShane cited articles from more than 20 years ago, contrasted with the information Mr. Thomas relied on from the past decade. AG/CUB opines that if Mr. Thomas' and Ms. McShane's proposed growth rates are compared, it is clear that Ms. McShane's proposed rates would require the companies in her own sample to first, exceed their own historic growth rate, and second, significantly exceed the historic growth rate in GDP. AG/CUB avers that Ms. McShane has not supported this inflated level of growth with any meaningful analysis or explanation, and the Commission can not rely on her analysis because it relies on growth expectations that are inconsistent with expectations in growth for GDP.

AG/CUB states an additional problem with Ms. McShane's proposed growth rates is found in the projections of dividend payout ratios she uses in her analysis, which show that analysts do not expect the earnings and dividend growth rates of the sample companies to grow at the same rate. AG/CUB avers that in such a situation, neither the earnings nor dividend growth rates provide an accurate reflection of the sustainable growth investors are expecting.

AG/CUB states that when dividend payout ratios decline, investors will expect more growth to come from earnings, because more capital has been retained for internal investment in the business, which will result in the DCF overstating the cost of equity. Similarly, an increasing dividend payout ratio will cause investors to expect less growth from earnings, and the DCF will understate the cost of equity.

d. Beta

AG/CUB notes that Ms. McShane uses Value Line betas in her analysis, which are raw beta estimates adjusted for ―mean reversion.” AG/CUB argues that when Value Line performs the mean reversion adjustment, it incorporates three key assumptions: (1) betas are unstable; (2) betas will eventually move to 1.0; and (3) the risk of the utility companies will eventually move toward the overall risk of other non-utility companies. AG/CUB avers that by ―unstable,” Value Line is assuming that utilities, which typically have betas below 1.0, will tend to become more risky over time, and the beta will tend to move closer to 1.0. AG/CUB opines that this is essentially a presumption that state commissions will be unable or unwilling to maintain stability for a monopoly firm that can modify its earnings through a regulatory process, instead of against the opposition of competitors.

AG/CUB submits that studies show, however, that the beta of utility companies does move toward the average risk of other companies over time. AG/CUB argues that even the initial study commonly cited as the basis to support the mean reversion adjustment, by Professor Marshall E. Blume, questions the usefulness of a one-size-fits-all mean reversion adjustment. AG/CUB submits that while Dr. Blume found that the accuracy of betas was improved by some adjustment; he also noted that the use of the historical rate of regression to correct for the future rate will not perfectly adjust the assessments and may even introduce larger errors into the assessments than were present in the unadjusted data.

AG/CUB states that Dr. Blume uses a dynamic or changing adjustment factor in his study and concluded that a static adjustment, such as the one used by Value Line, was not conclusively better than a purely unadjusted beta. AG/CUB avers that while the Commission has accepted a static adjustment without question in the past, there is no evidence in this case that a ―one-size-fits-all adjustment” is reasonable or results in appreciably better beta estimates, and that with utility betas typically below 1.0, the unwarranted adjustment has the effect of improperly increasing betas and the overall CAPM cost of equity. AG/CUB urges the Commission to use a beta that is derived from betas reported by a variety of financial reporting sources.

e. Market Risk Premium

AG/CUB states there are two main approaches to deriving the EMRP input for a CAPM analysis: either EMRP estimates derived from the academic studies of market performance are used, or an EMRP estimate is calculated for particular situations, noting Ms. McShane uses the latter approach. While Ms. McShane uses EMRP values of 9.1%, and 6.25 to 6.5%, in her analysis, AG/CUB argues the use of analysts' growth forecasts in determining investors' growth expectations is an unreliable method, and as a result, her EMRPs are grossly overstated.

AG/CUB avers that given the questions concerning how to determine the appropriate EMRP, the Commission should look to research and analysis performed by unbiased academics over many years instead of the assertions or ad hoc calculations of interested participants in economic contests. AG/CUB submits that the overwhelming conclusion from current research on the EMRP is that the return expected by investors and appropriate for use in the CAPM is far lower than returns calculated from selective samples of historic information. AG/CUB opines that the historic record, financial theory, and prospective estimates based on stock prices and growth expectations all indicate that the future equity premium in developed capital markets is likely to be between 3% and 5%, far lower than the 8% historic returns calculated from selective historic data.

AG/CUB asserts that in recent years, the Merrill Lynch expected return estimates have indicated an EMRP in the region of 4% to 5%, while an annual survey of pension plan officers regarding expected returns on the S&P's 500 for a five-year holding period indicated an EMRP in a 2% to 3% range. AG/CUB opines that Value Line projected market risk premiums are more volatile, ranging in recent years from 2% to 6%.

While Ms. McShane challenges this research, arguing it is no longer relevant because of the significant market correction and recent financial crisis, AG/CUB argues that Mr. Thomas examined this research, and provided updated information on current research reveals that a 5% EMRP may be too high. AG/CUB argues that current academic research looking at post-crisis equity risk premiums has shown that current estimates range from between 3.4% and 5.1%.

AG/CUB submits Ms. McShane's EMRP values are outside the estimates provided by the academic research, while Mr. Thomas used the higher end of the EMRP spectrum in his CAPM analysis, 5%. AG/CUB asserts that calculating an individual EMRP based upon analysts' forecasts inappropriately reflects the current short-term discontinuity, while the Commission's task is to set a cost of equity capital that is sustainable over the period that rates are in effect.

Ms. McShane proposes a historic equity risk premium and a DCF-based equity risk premium test, although AG/CUB notes the Commission has historically rejected risk premium analysis other than the CAPM. Ms. McShane also proposes a comparable earnings analysis, which AG/CUB points out the Commission has likewise traditionally rejected. AG/CUB submits that the Commission's task is to set rates for AIU based on the specific risks facing AIU.

While Ms. McShane argues that market-to-book adjustments are necessary to reflect differences between AIU book values of common equity and sample firms' market value capital structures, AG/CUB argues there is no evidence supporting such an adjustment, and the result would be to inflate the DCF cost of equity estimates above the already inflated results Ms. McShane's analysis produces. AG/CUB opines it has traditionally been the Commission's practice to apply unadjusted market-based DCF results to the book value rate base assets.

f. Proposed Adjustments

AG/CUB states that both of Staff's proposed calculations of the effect of the uncollectible riders are appropriate in determining the appropriate cost of common equity for AIU. AG/CUB submits these riders will ensure more timely and certain collection of bad debt expense and provide greater assurance that AIU will earn its authorized rates of return, reducing AIU's risk by reducing the uncertainty of cash flows by shifting the risk of under-recovery of uncollectibles expense from investors to the customers who pay their bills. AG/CUB avers that equity holders are exposed to more cash flow risk than debt holders because the structure of public utility debt assures that debt holders are paid first out of a companies' earnings, so the benefits of these risk reduction accrue directly to a companies' common equity shareholders. AG/CUB further notes that because these riders provide revenue stability, the value of this stability accrues directly to equity shareholders. AG/CUB states it is appropriate for the Commission to consider this when calculating AIU's cost of equity and the Commission should therefore adopt Staff's proposed adjustment for the uncollectible riders.

4. IIEC Position

a. Return on Equity Estimates

IIEC recommends that the Commission approve a ROE of 10.0% for the electric and gas utility operations of AIU. IIEC argues that its recommended ROE is a conservative estimate, as a comparison to Staff's recommended ROE shows that Staff's cost of equity estimate for gas operations is slightly lower, while the estimate for electric operations is slightly higher.

To estimate AIU's cost of equity, Mr. Gorman used a combination of analytical models. Employing a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, and a CAPM model, IIEC witness Gorman developed a return on common equity consistent with the governing legal standards. Because the AIU utility companies are not publically traded, Mr. Gorman and the other ROE witnesses in this case applied their models to groups of publicly-traded utilities with investment risk similar to that of AIU. IIEC states that Mr. Gorman analyzed the equity ratios and business risk profiles of the electric proxy group and AIU, and found that they are comparable in risk. Similarly, he found that the equity ratios, business risk profiles, and bond ratings of the gas proxy group are comparable. Mr. Gorman therefore used the electric and gas proxy groups developed and presented in the direct testimony of AIU witness McShane.

Mr. Gorman's DCF analysis is based on the premise that the price of an individual stock is determined by the present value of all expected future cash flows discounted at the investor's required ROR. IIEC notes that this theory has been accepted in the Commission's repeated reliance on DCF estimates as a basis for its cost of equity determinations. IIEC states that Mr. Gorman used two different versions of the constant growth DCF model. In both versions of his constant growth DCF model, Mr. Gorman relied on the average of the weekly high and low stock prices over a 13-week period ending August 21, 2009 for the stock price input into the model. Mr. Gorman judged the 13-week period to provide a reasonable balance between the need to reflect current market expectations and the need for sufficient data to smooth out aberrant market movements. For the dividend input to the model, he used the most recently paid quarterly dividend reported in the Value Line Investment Survey.

The first version of Mr. Gorman's constant growth DCF analysis relied on security analysts' growth rate estimates as the input representing the expected dividend growth rate. Specifically, he relied on security analysts' estimates for the companies in his proxy groups, from Reuters, Zacks, SNL Financial, and Thomson Financial, as reported on-line on August 24, 2009. Mr. Gorman averaged those results to develop growth rate estimate inputs. Mr. Gorman's constant growth DCF (analyst growth) analysis indicated average returns on equity of 12.19% for his electric group and 10.36% for his gas group.

IIEC avers, however, that Mr. Gorman concludes that this version of the constant growth DCF analysis produced unreliable results. Mr. Gorman observes that these results were based on a dividend yield (5.23%) that is distorted by current constrained market conditions and on a growth rate of 6.15%, which is not sustainable indefinitely, as the constant-growth DCF model requires. The growth rates for the electric group and gas groups exceed the projected rate of growth of the overall U.S. economy, are significantly higher than the historical dividend yield for the proxy groups, and diverge from their historical relationship with rate of inflation. The U.S. economy is projected to grow at a rate of 5% over the next 5-10 years. The average (6.67%) and median (5.63%) analysts' growth rate estimates for the electric group, and the average (5.84%) and median (5.67%) analysts' growth rates for the gas proxy groups exceed the projected rate of growth rate for the U.S. economy over the next 5-10 years. IIEC states that investment in utility plant is made to meet growth in demand for the utility's products, and that growth in demand is tied to economic growth of the utilities' service area. IIEC avers that historically, utility sales growth has lagged behind GDP growth, which thus represents a ceiling or high end sustainable growth rate for a utility over time.

IIEC argues that these dividend yield and growth factors are also inconsistent with each other, as they reflect contradictory outlooks for the utility industry. The factors that account for the recently higher dividend yield are drops in the stock price due to concerns about the economy, the level of utility sales, and decreased capital spending that slows rate base growth. Such factors tend to limit future earnings and dividend growth, but the growth rate component of the DCF model continued to reflect extraordinary and robust growth outlooks for both the electric and gas groups. Mr. Gorman, therefore, concluded the current market growth estimates for the proxy groups appear to contradict the growth outlooks reflected in the growth rate projections of security analysts. Specifically, Mr. Gorman notes that the historic dividend yields for his proxy groups were significantly lower than the current dividend yields for those groups. Mr. Gorman opines that the current dividend yield is driven by market uncertainty and the decrease in the stock prices of the proxy group, which in turn increased the proxy group dividend yield.

Mr. Gorman's second version of the constant growth DCF model uses the same inputs as the first, with the exception of the growth rate input. There Mr. Gorman uses a sustainable growth rate proxy for the expected growth rate. To develop this input, Mr. Gorman uses an internal growth rate methodology that includes external financing to develop that input. A sustainable growth rate estimates the amount of growth a utility can sustain indefinitely by retaining a percentage of its earnings, reinvesting those earnings in plant, and growing rate base and earnings for an indefinite period of time. Based on an assessment of sustainable long-term earnings retention rates, earned return on book equity, and an assessment of external growth opportunities if the utility sells stock at prices above book value, Mr. Gorman developed sustainable growth estimates for the electric and gas proxy groups. This constant growth DCF (sustainable growth) analysis produced an average return on common equity for his electric group of 10.48% and 9.62% for his gas group.

IIEC notes that Mr. Gorman conducted an additional DCF analysis that avoided the errors that arise from using current high analysts' growth rates that are not indefinitely sustainable, as proper application of the DCF model requires. IIEC opines that analysts' growth rate projections are intended to be a reflection of rational investment expectations over only the next 3 to 5 years. IIEC avers that a constant growth DCF model can not reflect a rational expectation that a period of high/low short-term growth can be followed by a change in growth rates that are more reflective of long-term sustainable growth. Mr. Gorman, therefore, performed a multi-stage growth DCF analysis to reflect the expectation of changing growth rates. Mr. Gorman's multi-stage growth DCF model reflects three growth periods: short-term (first 5 years); transition period (next 5 years); and long-term (11th year through perpetuity). For the short-term growth input, Mr. Gorman relied on the consensus analysts' growth projections used in his constant growth DCF (analyst growth) model. For the long-term period, he used the consensus projected growth rate in the U.S. economy, represented by GDP. For the transition period, the growth rate was changed annually to move linearly from the analysts' growth rates to the GDP growth rate. For the other model inputs, Mr. Gorman used the same 13-week stock price and quarterly dividends used in his constant growth DCF models.

This multi-stage growth DCF model produced an estimated common equity cost for his electric proxy group of 11.30%, and 9.93% for his gas proxy group. His estimates reflect the median return for the proxy groups, to eliminate the distorting effect of outliers among the results.

IIEC states that based on the results of only his sustainable growth rate, constant growth DCF model and his multi-stage, non-constant growth DCF model, Mr. Gorman concluded that the DCF returns on common equity for his electric and gas proxy groups were 10.78% and 9.79%, respectively. IIEC notes that Mr. Gorman excluded the unreasonable results of the constant growth DCF based on analysts' growth projections.

Mr. Gorman also relies on a CAPM analysis to develop his recommended return on common equity for AIU. IIEC asserts that because the risk-free rate is typically represented by U.S. Treasury securities, Mr. Gorman uses Blue Chip Financial Forecasts' projected 30-year U.S. Treasury bond yields for his risk-free rate. The beta term in Mr. Gorman's CAPM analysis is the average Value Line beta estimate for his electric and gas proxy groups of comparable companies. The expected market return used to calculate the market risk premium was developed by Mr. Gorman using two market risk premium estimates of the return on the market. The first was a forward-looking estimate based on published estimates of the long-term historical real return on the market (proxied by the S&P 500), plus consensus analysts' inflation projection. The second estimate was based on estimates of total return and risk-free return components of the long-term historical market risk premium published in Morningstar's Stocks, Bonds, Bills, and Inflation 2009 Yearbook.

IIEC states that because of concerns the Commission has expressed in the past about the use of only historical data in cost of equity analyses, Mr. Gorman confirms the reasonableness of the market returns used in his CAPM analyses by developing a third estimate. This return was an expectational market risk premium estimate using a DCF return on the market derived from multi-stage and sustainable constant growth models.

Mr. Gorman's CAPM analyses for his proxy groups produce a midpoint ROE estimate of 9.43% for his electric group and 9.01% for his gas group.

Based on the analyses discussed above, Mr. Gorman recommends a cost of equity for AIU of 10.0%. That recommendation reflects a two-thirds weighting for the electric proxy group result of 10.1% and a one-third weighting for the gas proxy group result of 9.4%. IIEC argues that because Mr. Gorman's recommended return on common equity is based on the cost of equity for companies with risks similar to that of AIU, it is commensurate with returns investors could earn by investing in other enterprises of comparable risk, and will allow capital to be attracted to AIU under reasonable terms.

IIEC avers that a 10.0% return on common equity will also allow AIU to maintain its financial integrity, as represented by an investment grade bond rating. Mr. Gorman's financial integrity analysis also confirms the consistency of his recommendation with the requirements of the foundational judicial decisions of Bluefield and Hope.

IIEC notes that Mr. Gorman assesses the adequacy of his recommended return on common equity by comparing key financial ratios for AIU to both the old and the new

S&P credit rating financial ratio guidelines for A and BBB rated utilities, with a business profile score of 5. IIEC states that Mr. Gorman constructed the S&P financial ratios for AIU's utility operations using its utility operations cost of service data (not parent company financials), its respective proposed capital structures, and his return on common equity of 10.0%.

IIEC opines that Mr. Gorman's analysis demonstrates that AmerenIP would be provided with the opportunity to produce a FFO to debt interest expense ratio of 2.7x. This interest coverage ratio is near the low end of the old range for BBB rated utility companies (2.8x to 3.8x) and within the new range (2.0x to 3.5x). IIEC notes that AIU's total debt to total capital ratio would be 54%, which is within the old ranges for BBB rated utilities. IIEC further states that AIU's retail operations FFO to total debt coverage would be 14%, which is within the new ranges for BBB rated utilities.

IIEC asserts that Mr. Gorman's analysis shows that AmerenCIPS would have the opportunity to produce an FFO to debt interest expense coverage ratio of 5.7x, which ratio is above the high end of the old range for BBB rated utility companies and above the high end of the new range. IIEC opines that this will support a strong A credit rating with AmerenCIPS' total debt to total capital ratio at 47%, which is within the old ranges of 42% - 50% for A rated utilities, while AmerenCIPS' retail operations FFO to total debt coverage would be 28%, which is within both the new and the old ranges for A rated utilities.

For AmerenCILCO, IIEC indicates that Mr. Gorman's analysis shows the utility would be provided with the opportunity to produce an FFO to debt interest expense coverage of 3.3x. This interest coverage ratio at the high end of the old range for BBB rated utility companies (2.8x to 3.8x) and within the new range (2.0x to 3.5x), while AmerenCILCO's total debt to total capital ratio would be 54%. IIEC avers that this is within the old ranges for BBB rated utilities. IIEC notes that AmerenCILCO's retail operations FFO to total debt coverage would be 18%, which is within both the old and new ranges for BBB rated utilities.

IIEC submits that its recommended return on common equity for AIU (10.0%) will allow each of AmerenCIPS, AmerenCILCO and AmerenIP to maintain its financial integrity. IIEC asserts that Mr. Gorman‘s DCF and CAPM analyses, updated to reflect more recent information, also support the recommended ROE of 10.0%.

IIEC argues that the costs of equity estimates developed by AIU are overstated, and should be rejected as the basis for the cost of equity determination in this case. IIEC asserts that there are several reasons why AIU's recommendations are inappropriate. IIEC avers that the most significant non-technical flaw is the fact that AIU's recommendations do not reflect recent changes in the financial market environment, with data taken mainly from time periods when the market was still severely distressed due to the market collapse of late 2008 and early 2009. IIEC opines that Mr. Gorman provides versions of his analyses that were modified to incorporate most of the methodology changes Ms. McShane recommended as part of her critique of his estimates and to use more recent data. IIEC states that these analyses show that simply updating Ms. McShane's input data had the most significant effect on her cost of equity estimates. Mr. Gorman's updated analyses produces a ROE of approximately 10.1%. IIEC argues that the 10.1% result of Mr. Gorman's updated analysis, incorporating the recommended changes of Ms. McShane, validates his original recommended ROE of 10.0% for AIU's gas and electric operations.

IIEC opines that a second reason Ms. McShane's recommended returns are overstated is her use of short-term growth forecasts in a constant growth model. IIEC notes that every expert in this case, including Ms. McShane, concludes that future growth will not be constant, because the forecast growth rates can not be sustained. IIEC avers that Ms. McShane's analyses incorporate the results of a model that assumes infinite constant growth, using an unsustainable growth rate, which mismatch has the effect of artificially inflating AIU's cost of equity estimates.

While AIU argues that Mr. Gorman's proposed combined ROE of 10.0% for AIU's gas and electric operations would result in cross-subsidies, erroneous investment decisions, and a misallocation of capital resources, IIEC argues that Mr. Gorman's recommendation reflects AIU's actual combination gas and electric investment fundamentals. IIEC notes that when AIU seeks capital in the market, AIU issues debt that reflects the risk of the combined gas and electric companies.

IIEC opines that from the perspective of the market, there is no separation in the investment risk of AIU's electric and gas operations, therefore a determination of the market-required cost of equity will reflect that consolidated risk profile, which results in common ROE, capital structure, and embedded debt cost determinations. IIEC avers that any separation of the electric and gas operations would not be based on true market information, but rather some allocation method devised to accomplish an artificial separation that does not exist in the market. IIEC asserts that the more direct and accurate measure of AIU's cost of equity is a determination of a fair ROE for AIU's consolidated operations. Should the Commission desire a ROE estimate that reflects the separation that AIU desires, then IIEC recommends 10.37% for electric operations, and 9.62% for AIU gas operations.

b. DCF and CAPM Model Issues

IIEC notes that through the testimony of its witness, Ms. McShane, AIU recommends that the Commission approve a ROE in the range of 11.75% to 12.25% for AIU's electric utility operations and a ROE in the range of 11.25% to 11.60% for AIU's gas utility operations, based on three DCF analyses, several risk premium studies, and a CAPM analysis. IIEC states that Ms. McShane also included in her recommendation, as an add-on to her model results, a leverage-type adjustment in the range 0.00% to 0.50% for electric, and 0.75% to 1.10% for gas.

IIEC argues that Ms. McShane's DCF return estimates are overstated, as they rely on growth rates in the constant growth rate DCF model that exceed reasonable estimates of long-term sustainable growth; while, Ms. McShane's DCF return estimates reflect dividend yields affected by the recent stock market downturn.

While Ms. McShane stated that Mr. Gorman‘s sustainable growth DCF model was in error because it did not include the external financing component, Mr. Gorman noted the external financing component was excluded because it indicated negative growth, which he concluded was not reasonable. Further, IIEC notes Mr. Gorman updated his sustainable growth DCF model to include the external financing model and it actually resulted in lower DCF return estimates.

IIEC avers that Ms. McShane‘s CAPM also produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group, while her CAPM return estimates for her gas group were in the range of 9.8% to 10.7%; based primarily on her use of an overstated market risk premium.

While AIU proposes to inflate its cost of equity estimates, to take account of the difference between AIU‘s equity ratios computed using the book value of its equity share, and those ratios when computed using the market values of equity shares, IIEC notes that the Commission has repeatedly rejected numerous variations of such ―leverage" adjustments that artificially boost the amount on which a utility earns a return. IIEC submits that no new evidence has been presented by AIU that should alter the Commission's position on this subject.

IIEC avers that Ms. McShane also estimated a ROE in the range of 15.0% to 16.0% based on a comparable earnings analysis that calculated the historical and projected returns on equity of 81 publicly traded companies. IIEC argues that this accounting-based return methodology does not measure the current market-based cost of capital necessary to attract investment and produces overstated returns in comparison to market-based (DCF, CAPM and Risk Premium) return estimates. IIEC opines that the Commission should continue to reject this flawed methodology.

While AIU argues in support of Ms. McShane‘s DCF estimate, stating that since she uses three DCF estimates, she therefore incorporates a potential range of utility investor expected returns, IIEC notes that one of the estimates incorporated in her analysis is the result of a constant growth DCF model that is inappropriate for the economic circumstances of record. IIEC opines that incorporating an estimate from a constant growth DCF model, which uses analysts‘ current growth forecasts as its long-term growth input, is not justified as its results are so inflated as to artificially raise an average with the other estimates.

Although AIU attacks Mr. Gorman's use of a multistage model, arguing that he has previously relied on a constant growth DCF model, IIEC notes that AIU's argument would appear to bind an expert to one estimation model and set of inputs for life, no matter the relevant circumstances. IIEC submits that Mr. Gorman relied on a constant growth model when it was appropriate, however as it does not now appear appropriate, he relies on a multi-stage model that is appropriate to the circumstances of record.

While AIU argues that Mr. Gorman's model selection substitutes subjective judgment for objective analysis, IIEC avers that Mr. Gorman used analysts' short-term projection for the period they are intended to represent, but rejected the short-term analysts projections as long-term growth projections. IIEC opines that short-term growth rates are not reasonable long-term growth rates estimates, and they are unsustainable when used for that purpose. IIEC submits that instead Mr. Gorman used an accepted estimate of a ceiling rate for utilities' long-term growth, and a gradual transition between the short and long-term rates.

c. Growth Rates

IIEC notes that Ms. McShane performed several DCF analyses, presumably for the same reason Mr. Gorman did, to take account of the current unsustainable nature of analysts' growth estimates. IIEC avers that Ms. McShane acknowledges, as the Commission has found, that long-term growth is effectively capped by GDP growth.

IIEC opines that Ms. McShane's estimates of growth are too high to be reasonable estimates of long-term sustainable growth, noting her constant growth DCF returns on equity were 13.6% for her electric group and 10.8% for her gas group. IIEC submits these returns were based on group average growth rate estimates of 7.1% and 5.3%, respectively, which growth rates IIEC finds far too high to be reasonable estimates of long-term sustained growth. IIEC avers it is not rational to expect that a utility company can grow indefinitely at a rate greater than the U.S. economy, noting U.S. economic growth is projected to be about 5.1% over the next 5 to 10 years.

IIEC argues that Ms. McShane's DCF estimate incorporates effects of the outlier estimate generated by that constant growth DCF model and her use of unsustainable analysts' growth rates as an input. IIEC states that her application of the DCF model failed to take proper account of the requirement that the indefinite cash flows discounted in a DCF analysis be generated using a growth rate that is sustainable indefinitely.

IIEC avers that Ms. McShane's DCF estimates also suffer from her use of stock prices that reflect anomalous market indicators from the recent financial crisis. IIEC argues that dividend yields calculated using stock prices from that period are unrepresentative of the improved financial environment, and using a more recent period that reflects the continuing market recovery would produce significantly lower dividend yields for her proxy groups.

While AIU asserts that analysts' growth forecasts are the most objective measure of investor expectations, incorporating them into a single-stage constant-growth DCF model, IIEC notes that Ms. McShane's own testimony contradicts the assumption of indefinite sustainability incorporated in her single-stage DCF model since she acknowledges that the growth rates used in constant growth DCF must be sustainable over the indefinite period the DCF model encompasses. IIEC avers that to the extent current three- to five-year earnings growth rate estimates are not reasonable estimates of long-term sustainable growth, the constant growth DCF analysis will produce highly problematic results.

Although AIU initially contended that Mr. Gorman did not accurately estimate the growth rate for his sustainable growth rate DCF model, IIEC states he updated his sustainable growth rate model which still supports an ROE of 10.0%. Although Ms. McShane opines that Mr. Gorman‘s revision to incorporate an external growth component failed to estimate it correctly, IIEC avers that despite her conclusion that Mr. Gorman‘s revision implies a significant decline in the utilities‘ market/book ratios, Ms. McShane presents no evidence to rebut Mr. Gorman‘s findings.

AIU argues that Mr. Gorman was incorrect in his assessment that analysts‘ short-term growth rates are too high to be reasonable estimates of long-term sustainable growth require one to reject investors as reasoning actors, and the market as an efficient reflector of investors‘ rational decisions. IIEC avers it simply is not reasonable to conclude that informed investors can not distinguish short-term and long-term forecasts, or that they would expect abnormally high growth rates to persist indefinitely. IIEC therefore requests the Commission reject AIU's argument on this issue.

d. Market Risk Premium

IIEC takes the position that Ms. McShane's CAPM produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group, while her CAPM return estimates for her gas group were in the range of 9.8% to 10.7%. IIEC states these estimates are the result of Ms. McShane's use of significantly overstated market risk premium inputs.

IIEC notes that Ms. McShane developed two estimates of the market risk premium, the first being based on a forward-looking equity risk premium. IIEC avers that in this study she used DCF analysis on the S&P 500 and subtracted her projected risk-free rate to estimate the market risk premium. IIEC states that her second estimate was based on the difference between the total achieved ROE securities and the income return on 20-year U.S. Treasury yields over the period 1926 through 2008, which produced an equity risk premium of 6.5%, comparable to the result (6.25%) of a similar analysis based on a 1947 through 2008 time frame.

IIEC opines the forward-looking market risk premium was calculated on the basis of her constant growth DCF return on the market of 13.8%, which was largely driven by a long-term sustainable growth rate of approximately 10.1% and dividend yield of approximately 3.7%. IIEC argues that such growth is more than twice the estimated growth rate of the overall U.S. economy and it is not rational to expect that a utility growth rate can be sustained indefinitely at a level above the growth rate of the U.S. economy.

IIEC states that if Ms. McShane's DCF return on the market and estimated market risk premium were adjusted to reflect rational growth outlooks and reasonable expectations by applying a multi-stage growth DCF model (short-term growth of 10.1% for 5 years, average growth rate of 7.5% for the 5-year transition stage, and a long-term growth at of 5.0% GDP rate), a more reasonable market DCF return of 9.8% would result. IIEC avers that subtracting Ms. McShane's risk-free rate of 4.7% results in a market risk premium of 5.1%, significantly lower than Ms. McShane's forward-looking market risk premium estimate of 9.1%.

IIEC notes that Ms. McShane also developed a historical market risk premium in the range of 6.25% to 6.5% which was based on the difference between the total achieved ROE securities and the income return on 20-year U.S. Treasury yields over the period 1926 through 2008. IIEC avers this produced an equity risk premium of 6.5%, which was comparable to the result of 6.25% of a similar analysis based on a 1947 through 2008 time frame. IIEC witness Gorman noted that despite Ms. McShane's flawed estimation process of subtracting only the income return (instead of the total return) on the U.S. Treasury yields, from the market equity return, recent anomalous movements in the stock market made the result (and only the result) of her estimation acceptable.

Mr. Gorman also noted that Ms. McShane uses a projected long-term risk-free rate of 5.7% for periods beyond the time rates set in this case will be in effect. IIEC argues those risk free rates are not representative of costs during the period rates are in effect and are not appropriate in setting rates that recover AIU's costs of service during that period. Further, Mr. Gorman noted that this risk-free rate significantly exceeds the current long-term U.S. Treasury yields in the range of 4.0% to 4.5% and the projected long-term U.S. Treasury yield of 5.0% over the next two years.

IIEC states that using a market risk premium in the range of 5.8% to 6.0%. a projected two-year U.S. Treasury bond yield of 5.0%, and beta estimates of 0.71 and 0.66 for electric and gas, respectively, would result in a CAPM ROE of 9.2% and 8.89%, which it would recommend.

IIEC opines that Staff's cost of equity recommendation is flawed by reliance on an overstated market risk premium in its CAPM analysis. IIEC notes Ms. Freetly recommended a ROE based on a non-constant DCF model and a CAPM risk premium analysis. IIEC states her CAPM estimate was based on market risk premium of 8.3%, estimated by subtracting her risk-free rate of 4.40% from the market return of 12.70%. IIEC avers this market return of 12.70% implies a dividend yield of 2.2% and a growth rate above 11.0%. IIEC argues this growth rate estimate is more than twice the expected long-term growth rate of the U.S. economy and produces an unreliable and inflated DCF market return. Mr. Gorman also noted that Ms. Freetly recognized the need for a sustainable long-term growth estimate, specifically, in the application of her non-constant DCF model.

IIEC notes that Ms. McShane used an ex-post (historical) market risk premium and one based on ex-ante (forward-looking) estimate in her analyses. IIEC states that Ms. McShane's forward-looking risk premium is a DCF-based return estimate for the

S&P 500, as a proxy for the market. IIEC avers the market-based DCF return used by Ms. McShane was based on an S&P dividend yield of 2.1% and a five-year IBES growth rate of 9.63%, yielding an expected return on the market of 12.0%. IIEC avers the 9.63% growth rate is substantially higher than the long-term expected growth of the U.S. economy, as represented by a GDP growth rate of 5.0%. IIEC argues that growth considerably faster than U.S. GDP growth can not be sustained indefinitely, making this DCF return of the market inflated and unreliable and overstating the market risk premium.

IIEC states that Staff developed a similar DCF return on the market which was also based on a growth rate that is too high to be sustainable. IIEC opines that both AIU's and Staff‘s market-based DCF estimates of the market risk premium are flawed and produce overstated premiums and CAPM return estimates.

IIEC states that Ms. McShane's historical estimate of utility equity risk premiums is derived based on achieved returns on utility stock relative to that of utility bond yields and U.S. Treasury bond yields. IIEC avers that Ms. McShane did not compare the actual historical achieved total return on utility stocks, relative to the historical total achieved returns on utility bonds and U.S. Treasury bond investments, but rather considered only the income portion of the total return of U.S. Treasury bonds to produce this equity risk premium. IIEC opines that Ms. McShane ignores changes in capital appreciations and losses for bonds, but she does reflect the change in market value for stock, resulting in a methodology that exaggerates the difference in actual total returns, and does not properly measure the premium investors actually achieved by investing in utility equities versus the compared bonds. IIEC submits that her methodology overstates the equity risk premium, and that correcting her analysis would substantially lower her utility bond equity risk premium estimates.

e. Proposed Adjustments

With regard to a proposed financial risk adjustment, IIEC notes that AIU criticizes Mr. Gorman‘s estimates as too low, in part because he did not include a leverage adjustment. IIEC states that Ms. McShane proposed to increase the electric ROE by 0.50%, and for the gas utilities in the range of 0.75% to 1.0%. While AIU attempts to validate its proposed adjustment by comparing it to Staff‘s risk adjustment, IIEC opines this is not an apt comparison. IIEC avers Ms. McShane‘s ―financial risk” adjustment is simply the latest guise for the leverage adjustment the Commission has consistently rejected as inappropriate. IIEC submits that by attempting to embed current market-to-book differentials in the Commission‘s authorized returns, the focus of the adjustment is Ameren‘s stock price performance, not the utility‘s market-required cost of equity. In contrast, as IIEC understands Staff‘s adjustment, it seeks to correct for measurable differences in the relative risk of AIU and the proxy groups used to estimate AIU‘s cost of equity.

5. IBEW Position

In IBEW's opinion, a sufficient ROE, as proposed by AIU, is necessary for the economic health of not only AIU, but also its employees, and should therefore be allowed by the Commission. Adoption of lower estimates, such as those proposed by Staff could potentially lower AIU's credit rating. Such downward pressure on AIU's credit ratings would create difficulties in securing financing and could force AIU to take other actions to maintain its financial integrity. Such measures could include a reduction in staff and contractors. Termination of employees, including members of IBEW, would result in further unemployment and damage to the Illinois workforce in this time of economic hardship.

6. AARP Position

AARP notes that in the previous AIU rate case, the Commission awarded its gas utilities an authorized ROE of 10.68% and its electric utilities an authorized ROE of 10.65%. (Docket Nos. 07-0585 et al. (Cons.)). AARP states that since that time, turmoil in the credit markets has created uncertainty about future expectations, due to an inability to predict deep, broad-scale declines in value, like the one that preceded our nation's recent recession. AARP believes, in light of this recent crisis, that the inputs to the accepted DCF analysis and the CAPM must be seriously re-evaluated, as these tools failed to fully predict or explain recent market behavior.

AARP submits it has also been shown how financial information from ratings agencies can be dramatically wrong, and states that serious allegations regarding the objectivity of credit ratings agencies are being made by former employees of these firms. AARP opines that utilities are now considered a safe haven for many investors, and thus it would not be reasonable to use the recent chaos of the markets as a basis for allowing an excessive ROE.

Therefore, AARP supports the cost of common equity recommendations of CUB witness Thomas. AARP notes Mr. Thomas performed an independent estimate of the cost of capital for the utilities in this case, using as a primary tool a DCF model that used a multi-stage, or —non-constant growth model," along with a separate CAPM analysis that confirmed these results. Based on these studies, AARP states Mr. Thomas recommends an 8.76% cost of common equity for AIU's electric operations and 7.97% for AIU's natural gas operations.

After the Commission has determined the proper cost of equity for AIU, AARP further recommends the Commission make downward adjustments to recognize the lessened risk associated with the new uncollectibles riders. AARP opines these riders will create greater certainty regarding the collection of bad debt expense, creating greater assurance of cash flows and greater likelihood that AIU will earn its authorized rates of return, significantly reducing the companies' risk.

AARP states that while the various consumer parties in this case generally agree that the risk reduction impact of the new Riders GUA and EUA should be taken into account, Staff witness Freetly is the only witness that has attempted to develop a comprehensive metric for quantifying the impact that would have on the cost of equity for AIU. While Mr. Thomas describes her methodology as conservative, he suggests that Ms. Freetly's recommended adjustments would be reasonable. AARP endorses Ms. Freetly's approach, because it reasonably quantifies significant factors that undoubtedly lessen business risk going forward if the new Riders GUA and EUA are adopted.

7. Commission Conclusion

AIU, Staff, IIEC and AG/CUB have each presented their own cost of equity analyses for this proceeding. AIU witness McShane's recommendation is based on her three DCF models, (1) a constant growth model that relies on analysts' earnings forecasts; (2) a sustainable growth model; and (3) a multi-stage model that includes both analysts' forecasts and nominal GDP growth as proxies for longer-term growth; as well as her risk premium studies and a CAPM analysis. Staff witness Freetly's recommendation is based on a non-constant DCF analysis and CAPM analysis. CUB witness Thomas utilized a non-constant growth DCF model to estimate AIU's cost of equity, along with CAPM to justify the results. IIEC witness Gorman employed a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, and a CAPM model to attempt to develop a return on common equity.

AIU recommends for the gas delivery service operations of AmerenCILCO, AmerenCIPS, and AmerenIP, the cost of common equity be set at 11.2%, 10.8%, and 11.2%, respectively, while for the electric utilities, the recommended cost of common equity is 11.7%, 11.3%, and 11.7%, respectively. Staff calculates costs of equity for the gas operations as 9.64% for AmerenCILCO, 9.38% for AmerenCIPS, and 9.64% for AmerenIP. For electric delivery service operations, Staff recommends costs of common equity of 10.38% for AmerenCILCO, 10.14% for AmerenCIPS, and 10.44% for AmerenIP. IIEC proposes a combined ROE of 10.0% for AIU's that reflects AIU's actual combination gas and electric investment fundamentals, while AG/CUB calculates that the cost of common equity for AIUs' electric operations is 8.76% and the cost of common equity for AIU's gas operations is 7.97%.

Before the Commission turns to the details of the parties ROE estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. The Commission must balance two competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, neither does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary. The Commission recognizes that it must also consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While the Commission recognizes that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record, and consistent with previous Commission decisions, to the extent possible.

a. CAPM

According to financial theory, the required ROR for a given security equals the risk-free ROR plus a risk premium associated with that security. This risk premium methodology is consistent with the theory that investors are risk-averse and that, in equilibrium, two securities with equal quantities of risk have equal required rates of return. The Commission notes that the parties are in agreement that a CAPM analysis requires three inputs or parameters, the beta, the risk-free rate, and the required ROR on the market. It is there, however, that the parties begin to diverge.

It appears to the Commission that both Ms. McShane and Mr. Gorman utilize Value Line (adjusted, weekly) betas to their CAPM analyses, while Ms. Freetly recommends equally weighing weekly and monthly betas, contending that neither weekly nor monthly betas are superior to the other. Mr. Thomas argues in favor of the use of unadjusted betas, asserting there is no evidence to support the use of regression betas, and claims the mean reversion adjustment is inappropriate and overstates the beta parameter, particularly for utility companies. Mr. Thomas urges the Commission to reject the analyses of AIU, Staff, and IIEC, as all parties used adjusted betas in arriving at their results, and Mr. Thomas suggests that unadjusted betas are superior when calculating a utility's ROE.

Staff calculated the risk-free rate parameter by considering the 0.14% yield on four-week U.S. Treasury bills and the 4.40% yield on 30-year U.S. Treasury bonds, with both estimates measured as of August 18, 2009. Staff noted that forecasts of long-term inflation and the real risk-free rate imply that the long-term risk-free rate is between 4.3% and 5.2%. 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 risk-free rate, Ms. McShane uses the forecast 30-year U.S. Treasury yield expected to prevail over the same five-year time frame for which the forecast growth rates for the market are made. IIEC states that because the risk-free rate is typically represented by U.S. Treasury securities, Mr. Gorman used Blue Chip Financial Forecast's projected 30-year U.S. Treasury bond yields for his risk-free rate.

It appears to the Commission that Ms. McShane first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return, then calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return. Ms. McShane also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.

Staff performed a constant-growth DCF analysis on the electric and gas samples to determine an appropriate market risk premium. Staff recognizes that some of the growth rates used in Staff's DCF analysis of the S&P 500 are unsustainably high, which produces an upward bias in Staff's market return estimate, and, thus in Staff's CAPM cost of equity estimate. Staff avers that while there is upward bias in Staff's estimate of the market return, there is no way to know the extent of the bias. Staff notes it did not use a non-constant growth DCF to estimate the return on the market because of the extreme difficulty of applying the more elaborate model to 500 companies.

AG/CUB argue that to determine an appropriate EMRP, the Commission should look to research and analysis performed by academics over many years instead of the assertions or ad hoc calculations of interested participants in economic contests. AG/CUB state that current research on the EMRP shows the return expected by investors and appropriate for use in the CAPM is far lower than returns calculated from selective samples of historic information. AG/CUB opines that the historic record, financial theory, and prospective estimates based on stock prices and growth expectations all indicate that the future equity premium in developed capital markets is likely to be between 3% and 5%, far lower than the 8% historic returns calculated from selective historic data.

IIEC calculated the expected market return to determine the market risk premium in two ways. The first was a forward-looking estimate based on published estimates of the long-term historical real return on the market, proxied by the S&P 500, plus consensus analysts' inflation projections. The second estimate was based on estimates of total return and risk-free return components of the long-term historical market risk premium published in Morningstar's Stocks, Bonds, Bills and Inflation 2009 Yearbook. IIEC states that it applied a multi-stage growth DCF model (short-term growth of 10.1% for 5 years, average growth rate of 7.5% for the 5-year transition stage, and a long-term growth at of 5.0% GDP rate) to arrive at a reasonable market DCF return of 9.8%. IIEC suggests then subtracting Ms. McShane's risk-free rate of 4.7% to arrive at a market risk premium of 5.1%, significantly lower than Ms. McShane's forward-looking market risk premium estimate.

The Commission has reviewed the testimony and arguments of the parties on this issue, and does not find AG/CUB's arguments regarding betas convincing. The Commission is of the opinion that the continued use of adjusted betas, when combined with appropriate proxy groups, is appropriate and should continue. The Commission further finds that Staff's use of both weekly and monthly betas, is superior to the use of only one or the other. It appears from the testimony that there are weaknesses present in both monthly and weekly beta estimates; however the use of both should ameliorate those weaknesses and assist the Commission in identifying this input which measures investor's expectations of the quantity of non-diversifiable risk inherent in a security. The Commission finds that Mr. Thomas' use of unadjusted betas is inconsistent with the determination of an appropriate return on common equity; therefore his CAPM analysis will be rejected and will not be considered.

The Commission believes that both AIU and IIEC appear 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. The Commission finds that Staff's constant-growth DCF analysis of the S&P 500 to determine the appropriate market risk premium is superior in this instance. The Commission further finds 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.

As the Commission does not find significant fault with any of the inputs of Staff's CAPM, the Commission will utilize it in developing estimates of cost of equity.

b. DCF

The Commission will next consider the various issues relating to the DCF model and the inputs thereto. Ms. McShane proposes the use of both constant growth and non-constant growth DCF models, while Ms. Freetly applied a multi-stage, non-constant growth quarterly DCF model. Mr. Gorman performed both constant growth and non-constant growth DCF models; however, he rejected the use of the constant growth model as its results were based on growth rates that were not sustainable. Mr. Thomas also suggests a non-constant growth DCF model be adopted. Mr. Gorman did, however, rely of his estimate of sustainable growth in the constant-growth DCF model, which he combined with his non-constant growth DCF model results. The Commission believes that the quarterly DCF model should be utilized to estimate the cost of common equity, as demonstrated by numerous previous Commission decisions. It is the Commission's opinion that the use of this model accurately recognizes the timing of cash flows to investors, which is necessary to estimate the investor required ROR. Use of an annual DCF model, the Commission believes, would unnecessarily introduce measurement error and downward bias to the results.

Ms. McShane uses two DCF models which the Commission will consider for this proceeding. Her testimony indicates she has modeled both a sustainable-growth DCF model and a three-stage DCF model, both with quarterly compounding of dividends. For the three-stage model, she relies on the IBES consensus of analysts' earnings forecasts for the first five years, and the average of this growth rate with the forecast nominal growth in the economy for the second five-year period, while for the third stage, growth equals the forecast nominal rate of growth in the economy (GDP). The expected long-run rate of growth in the economy is based on the consensus of economists' forecasts found in Blue Chip Economic Indicators. As estimates of the growth parameter in the constant growth model, Ms. McShane relies on analyst's growth forecasts and her estimate of sustainable growth.

AIU argues the use of the average of the constant growth and the three-stage DCF models, rather than the results of the three-stage model alone, recognizes the imprecision of the period during which investors might expect analysts' forecast growth rates to persist and avoids results that are potentially internally inconsistent. As a result, AIU believes a reasonable approach is to give equal weight to the results of both the constant growth and multi-stage models.

Staff and IIEC believe analyst growth rates are currently so high as to not be sustainable in the long run for use in a constant growth model, and this model therefore produces ROE results which are unreasonable in this instance.

Ms. Freetly modeled three stages of dividend growth for use in her multi-stage, non-constant growth DCF model. For her first stage, she assumed a growth stage of five years. Her second stage is a transitional stage lasting from the fifth to the tenth year, while the third or "steady" stage growth rate begins after the tenth year. For the first stage, Ms. Freetly used the market-consensus expected growth rates from Zacks, for the third stage she used the 20-year forward U.S. Treasury rate, and the middle stage was an average of the first two rates.

Mr. Gorman modeled a three-stage, non-constant growth DCF model, where the short-term growth period (years 1-5), relied on the consensus analysts' growth projections. In the third stage starting in the year 11, he used the long-term GDP forecast as a long-term sustainable growth rate, while the transition growth stage (years 6-10), used an annual linear change from the short-term growth to the long-term growth.

Mr. Thomas uses a three-stage DCF test, with the three stages being 1) for the short-term that the sample companies will grow at their average internal growth rate over the last five years, 2) for the intermediate-term that growth for the sample companies will trend toward the historical average growth rate in real GDP, and in the final stage, 3) a forecast of real economic growth excluding inflation, rather than nominal growth.

The Commission notes that in the past, it had traditionally relied on a constant growth DCF model with analysts' estimates of EPS growth in developing the cost of common equity for utilities in rate cases. In recent years however, the Commission has begun using a non-constant growth model as analysts projected growth rates for utilities have exceeded the projected growth rate of the U.S. economy as a whole. The Commission notes that the recent Peoples/North Shore rate case, Docket Nos. 09-0166/09-0167 (Cons.) did adopt the use of a constant growth DCF model, however, as each utility is different, and each rate proceeding should be judged on its own merits, the Commission finds that the record supports a conclusion that it would be inappropriate in this matter to adopt a constant growth DCF model.

The Commission notes that Staff and IIEC and AG/CUB are in agreement that at least in this instance, the use of a single-stage, constant growth DCF model is inappropriate, as analyst's estimates for earnings growth are currently unreasonably high and are not sustainable for utilities. The Commission agrees that the traditional constant growth model would in this instance result in suggested growth rates that would exceed the growth rate for the U.S. economy in perpetuity, which appears unlikely. The Commission finds that Mr. Thomas' DCF model inappropriately uses historical growth rates for near term growth. An additional problem with Mr. Thomas' DCF analysis is his proposal to rely upon expected real growth in the economy, which ignores the fact that investor expectations include a return that reflects expected inflation. Mr. Thomas' DCF analysis is problematic and it will not be considered here. The Commission will also decline to use either Ms. McShane's sustainable growth DCF model, or her three-stage DCF. The Commission finds that like Mr. Thomas, Ms. McShane's over-reliance on historical data is problematic. Like Ms. McShane, Mr. Gorman also used a sustainable growth factor in the constant-growth DCF model. The Commission is of the opinion that sustainable growth estimates are problematic in that they rely upon a proxy for ROE as an input when estimating the investor required return. The Commission finds such an approach troubling and notes it has traditionally rejected DCF models that rely on sustainable growth, and will continue this practice in this proceeding.

The Commission finds merit in both IIEC and Staff's non-constant growth DCF models, and as such they will be considered when estimating AIU's costs of common equity for this proceeding. It further appears to the Commission that while Mr. Gorman generally recommends a combined cost of equity for the gas and electric operations of AIU, the Commission finds it more appropriate to use the results of his non-constant growth DCF model with the results computed separately for the gas and electric operations, as evidenced by Mr. Gorman's rebuttal testimony. (See IIEC Ex. 6 at 4)

c. Risk Premium Study

Mr. Gorman and Ms. McShane also presented the Commission with a risk premium analysis in addition to the DCF models and CAPM models. Although it does not appear to the Commission that a great deal of discussion occurred in the parties briefs on this model, other than footnotes by AIU and IIEC, the Commission notes it has traditionally rejected risk premium analyses. The Commission finds no reason to deviate from past practice wherein it has relied on the DCF and CAPM models to estimate cost of common equity. The Commission declines to consider either AIU's or IIEC's risk premium analysis.

d. Adjustment for Financial Risk

AIU has proposed that an adjustment be made to the cost of common equity calculations to reflect increased financial risk for AIU. Staff and AIU agree that when a utility has more or less financial risk than the sample companies used to estimate the cost of equity, an adjustment to the cost of equity is necessary. Ms. McShane asserts that when the market value common equity ratio is higher than the book value common equity ratio, the market is attributing less financial risk to the companies than the book value capital structure suggests.

Staff maintains that there is no merit to Ms. McShane‘s claim, arguing the fundamental problem with Ms. McShane‘s claim is that it assumes, without foundation, that the book value capital structure of the AIU directly reflects investors‘ perceptions of the financial risk of the AIU. Staff opines that while investors are unlikely to ignore the book value capital structure of companies generally and utilities specifically, investors' perceptions of AIU's financial risk inherent in its book value capital structure are not observable because its common stock is not market traded. IIEC states that the financial risk adjustment proposed by AIU attempts to change the focus of this proceeding to Ameren's stock performance, rather than AIU's market required cost of equity. IIEC recommends adopting Staff's adjustment, as it seeks to correct for measurable differences in risk between AIU and the various proxy groups. AG/CUB urge the Commission to reject AIU's proposed financial risk adjustment, noting that the Commission applies a market-determined ROR to the book value of the capital structure, and AIU presents no evidence that a change from this practice is required. AG/CUB opines that adjusting market-based DCF results before applying them to the book value of assets in rate base inflates the market-based cost of equity.

The Commission is satisfied that Staff's suggested adjustment is appropriate to compensate for the different financial risk between AIU and the gas and electric proxy groups, and it is approved for the purposes of this proceeding. It appears to the Commission that AIU's proposed adjustment is, as suggested, an attempt to impose a market value adjustment, which the Commission has consistently rejected. The Commission does not support making an adjustment to the authorized ROE due to differences and book value and market value, and the Commission declines to adopt the recommendation that it do so.

e. Adjustment for Reduced Risk of Gas Operations

The Commission notes that in AIU's last rate proceeding (Docket Nos. 07-0585 et al. (Cons.)), the Commission chose to make the decision to authorize the recovery of more of AIU's fixed costs through the customer charge, with 80% of fixed costs being recovered through the fixed customer charge. As a consequence of that decision, the Commission also chose to reduce the return on common equity for AIU's gas operations by 10 basis points, to reflect what was viewed as a reduction in the risk that AIU would not recover its fixed costs of doing business.

Staff has recommended that the Commission again reduce the authorized rate of return on common equity for AIU's gas operations due to the increased fixed customer charge, while AIU claims the reduced risk has already been reflected in the gas sample used to estimate the cost of common equity, obviating the need for any additional reduction. The Commission, however, agrees with Staff's analysis that although some of the companies in the gas sample may have some type of de-coupling mechanism in place, there is no showing that it applies to the entire gas sample. The Commission will therefore adopt a 10 basis point reduction in the return on common equity for AIU's gas operations to reflect the reduced risk to due to the increase in fixed portion of the customer charge. The Commission is satisfied that this change, adopted in AIU's last rate proceeding, and continued here, places AIU at less risk of recovering less than its fixed costs of service for gas operations, which should be reflected in a reduction in the approved cost of common equity for AIU's gas operations.

f. Adjustment for Uncollectible Riders

The Commission takes note that in Docket No. 09-0399, uncollectible riders were approved for both the electric and gas operations of AIU, in conformity with Public Act 96-0033, which added Section 16-111.8 to the Act for electric utilities and Section 19-145 for gas utilities. These sections of the Act are substantively identical and provide electric and gas utilities with the opportunity to establish an automatic adjustment clause tariff for the collection of "uncollectibles," which opportunity AIU availed itself of. The Commission agrees with Staff that there is a benefit to AIU with the adoption of the uncollectible riders, and a portion of that benefit should accrue to ratepayers through a reduction in the allowed cost of common equity. AIU disputes there is a benefit such as Staff suggests, and criticizes Staff's method of attempting to calculate the effect of the riders on AIU. AIU suggests that should the Commission find a reduction to the cost of common equity appropriate, no more than a 10 basis point reduction would be appropriate. With regard to AIU's claim that the uncollectibles riders do not reduce its risk because there is still a chance that the Commission may find that it acted imprudently, the Commission reminds AIU that it largely controls the outcome of any such prudence review so long as it acts prudently in attempting to recover unpaid amounts.

Staff has attempted to calculate the effect of the uncollectible riders in two ways. The first attempts to discern the effect the riders will have on the rating agencies opinion of each utility by updating the rating factors, and thereby determining a proposed new credit rating for AmerenCILCO, AmerenCIPS, and AmerenIP. The second approach is characterized as a more iterative process with Staff attempting to calculate what the effect would have been on each utility in years past had the riders been in effect and thereby determining the differences in income for each company with and without the rider. Staff then would have the Commission average the results of each method to determine an appropriate reduction.

While the Commission commends Staff for its efforts in determining the effects of the uncollectibles riders, it appears to the Commission that the results of what is characterized as the iterative approach does not appear to provide a reliable estimate of the reduction in risk. Staff states the results of its iterative approach would produce downward adjustments in the costs of equity for the gas operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 160, 149, and 106 basis points, respectively, to reflect the risk reduction associated with Rider GUA; while producing downward adjustments to the costs of common equity for the electric operations of AmerenCILCO, AmerenCIPS, and AmerenIP of approximately 76, 119, and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

The Commission contrasts these results with Staff's first approach, which suggests reductions of 15 basis points for AmerenCILCO and AmerenIP, and 10 basis points for AmerenCIPS natural gas operations; and reductions of 50 basis points for AmerenCILCO, 10 basis points for AmerenCIPS, and 20 basis points for AmerenIP electric delivery service operations. The Commission finds Staff's reasoning in calculating its first approach persuasive and reasonable, and the Commission will adopt the results set forth in this paragraph for this proceeding. The Commission agrees with Staff that the adoption of the uncollectible riders ensure more timely and certain collection of bad debt expense and should provide AIU with greater assurance that they will earn their authorized rates of return. Due to this reduction in uncertainty, the Commission finds it appropriate to adopt a reduction to the approved cost of common equity. Staff's first approach, which estimates the effect the adoption of the uncollectible riders will have on AIU's Moody's credit rating and the resulting change in implied yield spreads appears to be reasonable to reflect the benefit of the adoption of the uncollectible riders. While Staff's second approach is intriguing, it appears the results shown from the second set of calculations are somewhat in excess of what might be expected from the adoption of these riders, and they will therefore not be used in calculating the appropriate reduction in ROE.

g. Authorized Returns on Equity

Having addressed the significant contested issues that relate to cost of common equity, it appears to the Commission, as discussed above, that there are significant shortcomings with respect to the analysis of CUB witness Thomas. His suggested non-constant growth DCF analysis employs inappropriate inputs, particularly his growth rates. His suggestions concerning CAPM are also rejected, along with his suggested EMRP and his proposal to use unadjusted betas. Likewise, Mr. Gorman's Risk Premium and CAPM analysis are rejected and will not be considered as they rely too heavily on historical returns in calculating a forward looking recommended ROE. Similarly, Ms. McShane's CAPM analysis is rejected, primarily for its reliance on historical data and its questionable reliance on forecast U.S. Treasury rates. As discussed above, the Commission finds Mr. Gorman's constant growth DCF analysis which incorporates his estimate of sustainable growth to be problematic and the Commission declines to rely upon it.

The Commission finds value in both Staff's and IIEC's non-constant DCF analyses, along with Staff's CAPM analysis. Each has suggested the use of a multi-stage DCF model in this instance to mitigate the impact of unsustainable analyst estimates of growth, using instead estimated proxies of U.S. GDP growth as the long-term growth rate. Staff's DCF analysis, based on a three-stage model, results in a recommended ROE of 9.79% for AIU's gas operations, and 10.67% for AIU's electric operations. IIEC's non-constant DCF analysis, likewise using a three-stage approach, results in a ROE estimate both electric operations of 10.73% and 9.46% for gas operations. Staff's CAPM analysis resulted in a cost of equity recommendation of 9.46% for AIU's gas operations and 10.21% for AIU's electric operations.

The Commission finds IIEC's non-constant growth DCF analysis, along with Staff's non-constant growth DCF and CAPM analyses, to be without material flaws, and should be considered in establishing AIU's cost of common equity. The Commission further notes that Staff proposes to adjust the recommended electric results downward by 6 basis points for AmerenCILCO and 30 basis points for AmerenCIPS, to reflect the lower financial risk of AmerenCILCO and AmerenCIPS relative to the electric proxy group. Staff further proposes to adjust its recommended gas results upward by 10.5 basis points for Ameren CILCO and AmerenIP to reflect a higher financial risk than the gas proxy group, and the results for AmerenCIPS down by 15 basis points to reflect a lower financial risk relative to the gas proxy group. The Commission notes this adjustment appears reasonable and it will be adopted for calculating the recommended ROE.

Having reviewed the evidence and arguments, the Commission concludes that AIU's cost of common equity is 9.54% for gas operations and 10.46% for electric operations. These returns on common equity give equal weight to the results of Staff and IIEC DCF analyses, which is combined with Staff's CAPM analysis. As indicated above, the authorized ROE for AIU's natural gas operations is adjusted downward by 10 basis points to reflect the reduced risk from the approved gas customer charge. The authorized ROE will also be reduced by 15 basis points for AmerenCILCO and AmerenIP, and 10 basis points for AmerenCIPS natural gas operations; and by 50 basis points for AmerenCILCO, 10 basis points for AmerenCIPS, and 20 basis points for AmerenIP electric delivery service operations to reflect the reduced risk to each company as a result of the adoption of the uncollectible riders.

The tables below illustrate the approved ROE that the Commission adopts for purposes of this proceeding.

AmerenCILCO

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	
Risk Adjustments				
Financial Risk	-0.06%		0.105%	
Uncollectibles	-0.50%		-0.15%	
Fixed Customer Charge			-0.10%	
Approved ROE	**9.90%**		**9.40%**	

AmerenCIPS

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	

Risk Adjustments		
Financial Risk	-0.30%	-0.15%
Uncollectibles	-0.10%	-0.10%
Fixed Customer Charge		-0.10%
Approved ROE	**10.06%**	**9.19%**

AmerenIP

	Electric		Gas	
	DCF	CAPM	DCF	CAPM
Staff	10.67%	10.21%	9.79%	9.46%
IIEC	10.73%		9.46%	
Average	10.70%	10.21%	9.63%	9.46%
Unadjusted ROE	10.46%		9.54%	
Risk Adjustments				
Financial Risk	0.00%		0.105%	
Uncollectibles	-0.20%		-0.15%	
Fixed Customer Charge			-0.10%	
Approved ROE	**10.26%**		**9.40%**	

H. Commission Authorized Rates of Return on Rate Base

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 8.05% ROR on net original cost rate base for electric operations; AmerenCIPS should be authorized to earn an 8.02% ROR on net original cost rate base for electric operations; and AmerenIP should be authorized to earn an 8.97% ROR on net original cost rate base for electric operations.

Taking into consideration the Commission's conclusions regarding capital structure, cost of short-term debt, cost of long-term debt, and cost of common equity, the Commission finds that AmerenCILCO should be authorized to earn an 7.83% ROR on net original cost rate base for gas operations; AmerenCIPS should be authorized to earn an 7.59% ROR on net original cost rate base for gas operations; and AmerenIP should be authorized to earn an 8.59% ROR on net original cost rate base for gas operations. The appendices to this order show the development of the authorized returns on rate base.

VII. RIDERS

A. Revisions to Rider S - System Gas Service and PGA Uncollectibles

In AIU's last rate cases, the Commission directed AIU to remove the uncollectible expense component associated with the PGA from the gas delivery service base rates paid by transport customers served under Rider T - Gas Transportation Service ("Rider

T"). In response to this directive, AIU proposes to unbundle PGA-related uncollectible expenses and incorporate those expenses into Rider S - System Gas Service ("Rider S") with class-specific uncollectible recovery factors that will apply to the PGA charge components. AIU states that this will provide more precision in ratemaking by segregating delivery costs from purchased gas costs and provide a better matching of revenue and uncollectibles expense. AIU and Staff have agreed to calculate the Rider S uncollectibles factor using an average of the most recent actual information for the period January 2007 through September 2009. AIU provided revised PGA uncollectibles factors that are based entirely on actual information. AIU proposes to incorporate those proposed PGA uncollectibles factors into Rider S on Sheet 24.001 of the Gas Services Tariffs. The Commission finds this proposal reasonable and adopts it.

B. Rider VGP - Voluntary Green Program

1. AIU Position

As part of its rate cases, AIU proposes a new rider for Commission approval: Rider VGP - Voluntary Green Program ("Rider VGP"). Rider VGP would be available to electric delivery service customers interested in financially supporting the development of renewable energy technologies. If approved, AIU states that Rider VGP will be another means to promote the federal and state policy for cleaner, renewable energy. AIU also requests that the Commission find that the offering and promotion of Rider VGP to delivery service customers will not be deemed a violation of Section 452.230, Permissible and Impermissible Integrated Distribution Company Services, of the Commissions rules concerning integrated distribution companies ("IDC") set forth in 83 Ill. Adm. Code 452, "Standards of Conduct and Functional Separation." Because participation in Rider VGP does not alter the amount of energy and power supply commodity purchased by a customer, nor does it limit or alter the customer‘s energy and power supply options, AIU does not believe that the offering of Rider VGP pursuant to the proposed rider would violate the IDC rules. If approved, AIU proposes that the rider begin 60 days from the date of service of the order.

In describing Rider VGP, AIU states that the program relies on renewable energy credits ("REC"), meaning there is no renewable power and energy commodity provided to participants. Unlike power and energy, which are physical commodities, a REC can not power homes or businesses; rather, a REC represents the intangible environmental attributes of one megawatt-hour of power produced from a renewable energy project and is sold separately from the actual electricity commodity. AIU adds that RECs have been accepted by the Illinois Power Agency ("IPA") and the Commission as an appropriate method for complying with Illinois renewable energy requirements.

AIU plans to purchase RECs with revenue received from program participants. To offset out-of-pocket and other incremental costs, AIU proposes to mark-up the actual cost of the program RECs by 5%, not to exceed $1 per REC. AIU indicates that it may later request additional cost recovery in future rate cases if more costs are incurred than expected. Subsequent to each month, AIU will use the proceeds received from program participants, less administrative mark-up, to purchase the corresponding number of RECs on behalf of participating customers. AIU states that it is important for program participants and it to know the REC prices in advance of customer participation. The planned approach is for the customer to select its own level of participation: residential participants would select one of three monthly contribution levels ($3, $7, or $15), and non-residential customers would elect the number of RECs they wish to purchase each month. AIU will use a single round, pay as bid request for proposal ("RFP") process to acquire RECs for the program and will seek price certainty for RECs for an extended number of months, if not a year at a time. AIU plans to directly administer the RFP process and advertise in trade publications for broad exposure.

AIU is still attempting to determine the initial REC quantity. AIU proposes flexibility regarding the REC procurement process because this program is new and AIU can not predict the number of customers signing up or the financial level at which those customers wish to participate. Moreover, AIU plans to seek REC procurement terms that will keep REC costs reasonable and also allow as much flexibility as possible regarding the number of RECs, timing of REC payments, and deliveries. AIU prefers a flexible pay-as-you-go approach, but indicates that that preference must be balanced with the overall price of RECs under such an arrangement and the willingness of REC suppliers to sell under those terms. AIU believes that it would be premature to begin its REC procurement process prior to an order approving Rider VGP. AIU‘s preferred approach for contracting the purchase of program RECs would be to pay the supplier for RECs with proceeds collected from VGP participants. Since it can not predict the pace of customer sign-up, participation levels, and payment levels, however, AIU recognizes that it is possible that it will be required to pay for RECs before program participants pay for them. AIU states that it must be cautious that overly restrictive REC procurement requirements may limit the number of bidders or result in paying premium prices for the RECs. AIU also intends to make retirement of the RECs the responsibility of the REC supplier. AIU's role would be to (1) accumulate the quantity of RECs purchased under the program, at the end of the month, (2) notify the REC supplier of the quantity to be retired in AIU‘s name, and (3) review documentation provided by the supplier to verify the appropriate quantity was retired in AIU‘s name.

AIU‘s procurement objective would be to spread delivery and payment for the RECs (actual delivery of RECs retired on behalf of VGP participation) over an annual period. AIU adds that it may also have to purchase RECs at a faster pace than planned if program sign-ups exceed the monthly REC supply. The accounting entries present in Ameren Ex. 39.1 are intended to provide accounting entry detail to cover a REC prepayment scenario as well as a pay-as-you-go REC procurement scenario.

AIU will prepare internal reports on Rider VGP program activity to provide a transparent accounting for the program revenues, RECs, and incremental costs. Additionally, AIU explains it intends to procure RECs from resources located within the MISO or PJM regional transmission organization areas. AIU will rely on the same criteria for Rider VGP RECs as are set forth in Public Act 95-0481, regarding RECs for the Illinois Statewide Renewable Portfolio Standard. AIU plans to adapt a version of the REC contract used for its 2009 IPA Procurement.

The incremental costs of implementing Rider VGP are expected to be minimal. AIU states that it already has infrastructure in place to administer the program, channels to promote it, internal expertise to acquire and manage the RECs and to educate customers, and a capable billing system. AIU intends to use its current information channels and emerging communication avenues to publicize Rider VGP. AIU indicates that no additional costs have been built into the revenue requirement in this case for administering the proposed program.

In light of the experience of its affiliate AmerenUE and its own survey data, AIU contends that a market exists for Rider VGP among its customers. First, AIU indicates that its customers, especially those residing in the St. Louis metropolitan area, have expressed interest in participating in the AmerenUE Pure Power Program. Similar to Rider VGP, the Pure Power Program is a voluntary non-commodity program that provides an opportunity for AmerenUE electric customers to purchase RECs. Second, AIU conducted surveys to assess the level of Illinois residential customer interest in participating in a green program. According to AIU, survey results indicate a substantial level of customer interest in paying an additional monthly fee to participate in a green program.[10] Finally, the AmerenUE program, implemented in 2007, is similar to the AIU proposed program, and in its first year, 4,000 participants purchased approximately 42,000 RECs. AIU adds that the AmerenUE program is nationally recognized, including by the U.S. Department of Energy, which named it the "most successful" New Green Power Program of the year.

With regard to Staff's position on Rider VGP, AIU understands that Staff would like to see additional details in updated responses to Staff data requests and is unable to decide at this time whether Rider VGP would violate the IDC rules. Why Staff can not address the IDC rules at this time is unclear to AIU. AIU also understands that Staff is particularly critical of the lack of specific detail regarding the process to account for program transactions and reconcile program revenues with RECs. AIU acknowledges that its accounting systems must be able to track the Rider VGP program residential billed charges, non-residential billed charges, receipt of payment from participants, REC purchases, RECs retired by virtue of program revenues, and how to account for customers not paying for three consecutive billing periods. The AMS Controller‘s group recommended journal entries for the Rider VGP program. The proposed accounting entries are set forth in Ameren Ex. 39.1. AIU states that the proposed accounting entries will treat program revenue in above the line revenue accounts. Special monthly

[10] AIU reports that nearly 2,200 customers were asked if they would be willing to pay more on their electric bill each month to help produce additional power from renewable resources and answered as follows: 22% responded ―Yes;” 65% responded ―No;” and 13% responded ―Don‘t Know.” Customers that responded ―Yes” were asked how much extra they were willing to pay: about 33% agreed they would be willing to pay between $1 and $5 per month extra; 33% agreed they would be willing to pay between $5 and $10 extra per month; 14% agreed they would be willing to pay between $10 and $15 extra per month; 11% agreed they were willing to pay between $15 and $20 extra per month; and 8% agreed they would be willing to pay $20 or more extra per month.

reports will track and report participant payment data. AIU maintains that its financial system will facilitate separate tracking and reporting of program billed revenue, participant payments, and program costs. The entries also provide for the purchase of RECs.

Staff also recommends that, if the Commission adopts Rider VGP, the acquisition of RECs, as it relates to estimated participation levels, should first be addressed. Specifically, Staff asserts the timing for the purchase of RECs is unclear from the information provided by AIU. Staff's concern is that, if the RECs are pre-purchased in anticipation of estimated participation levels, a procedure should be in place for the variance between anticipated and actual participation levels. AIU states that it appears that Staff's confusion stems from Ameren Ex. 39.1, which illustrates accounting entries for the program costs and revenues. The prepaid accounting scenario is set forth in the second set of entries under Section 1 of Ameren Ex. 39.1, and Section 3 of that exhibit illustrates when Rider VGP participants pay for their program participation. Section 1 of that exhibit shows when there is a purchase of RECs from a supplier funded by Rider VGP revenues. Moreover, AIU believes that the Rider VGP program will provide Staff and the Commission with adequate data and information on which to monitor the financial transactions under the program.

2. Staff Position

In response to AIU's proposed Rider VGP, Staff opines that the program is not sufficiently designed or explained for it to recommend approval. Staff notes that AIU continues to discuss the accounting for Rider VGP in rebuttal testimony. Staff is also concerned with the timing of acquisition of the RECs. AIU admits that the REC procurement process has not yet been designed and that it is proposing to maintain flexibility regarding the procurement. Staff states further that its concerns with the treatment of the variance between anticipated and actual participation levels have not been addressed by AIU. If AIU is not yet able to clearly define and present its proposal, Staff contends that the Commission should be concerned that the customers to whom this plan will be marketed might not have a clear understanding of exactly what would be bought.

3. AG/CUB Position

Although the AG and CUB voice support for green energy initiatives, they urge the Commission to deny approval of Rider VGP. AG/CUB contends that AIU has not provided nearly enough information about Rider VGP to warrant Commission approval. As an example, AG/CUB notes that AIU has not yet designed the REC procurement process for the VGP Program. When asked for sample copies of whatever agreements, product orders (confirmations), and related documents that AIU intends to use when contracting with the REC suppliers, AG/CUB reports that AIU had no such agreements or documents at that time. This response concerns AG/CUB since AIU wants to begin offering RECs under Rider VGP 60 days from the date of the Commission's order.

AG/CUB notes that AIU has proposed numerous riders before the Commission and should be well aware of the type of detailed plan that Staff needs to review. Such detail, they contend, is sorely lacking as to Rider VGP. Nor, they continue, is there sufficient information for a review of any potential conflict with the Commission's IDC rules. AG/CUB finds this lack of information particularly troubling since this program will be marketed to residential consumers. Overall, AG/CUB argues that approval of Rider VGP based on such minimal information would be premature at this point.

Even if one assumed that Rider VGP does not violate IDC rules, AG/CUB states that AIU has not provided any details of what information (such as marketing materials) will be used to explain the program in plain language so that customers will understand. Information that they believe is missing includes: 1) what the cost/benefits of the Rider VGP program are; 2) how to meaningfully compare the value of the Rider VGP program with other potential or existing green programs, such as those offered by Alternative Retail Electric Supplier (―ARES") programs; 3) language clearly indicating to customers that the REC based program does not relate to physical delivery of green power to the customer, or does not directly relate to the development of green projects (such as a wind farm) locally or even in the AIU territory; and 4) a disclosure that every AIU customer will be contributing long term to green energy in Illinois through the IPA's procurement process. (See Docket No. 09-0373) Because there is nothing in the record for the Commission to evaluate the programs risks, or the customer value and benefits, AG/CUB recommends that Rider VGP be rejected.

4. AARP Position

AARP neither supports nor opposes Rider VGP. If Rider VGP is to be approved, however, AARP urges the Commission to mandate in its order that this program be clearly voluntary and that consumers be given enough accurate information to ensure that an informed decision can be made about whether to participate. Because of the risk of confusion, AARP further urges the Commission to require that all promotional materials relating to this program be reviewed and approved by the Commission to ensure that it is accurate and not misleading.

5. Commission Conclusion

While appreciative of AIU's effort to support renewable energy through the purchase of RECs under Rider VGP, the Commission is not convinced that the proposed Rider VGP is ready for approval. As Staff and AG/CUB noted, much remains to be determined about exactly how Rider VGP would function. The Commission understands that AIU can not predict participation levels in advance, nor can it be certain of REC prices and what terms REC sellers would accept. But beyond these uncertainties, too many other aspects of Rider VGP are unclear.

For instance, AIU proposes to markup RECs by 5%, not to exceed $1 per REC. How AIU determined that a 5% markup is appropriate is unclear. AIU also indicates that it may later request additional cost recovery in future rate cases if more costs are incurred than expected. The Commission finds unsettling the notion that it should approve this rider when the potential exists that its implementation costs may go up by an unknown amount. While it is reassuring to know that AIU believes that it can offer a new program without seeking new revenue, the Commission would prefer to know more about Rider VGP's costs before authorizing its initiation. If the Commission authorizes the program now only to learn during the next rate case that it may be too costly, customers may be unnecessarily confused.

The Commission is also concerned that end-user customers may not fully appreciate the character of RECs. While associated with renewable energy, no actual energy commodity is bought and sold when acquiring a REC. Whether customers would fully appreciate this distinction is unknown, but the answer would depend in large part on the Rider VGP educational materials provided by AIU. Sufficiently educating customers on RECs is certainly feasible.

The Commission notes that AIU customers are currently obligated to purchase RECs pursuant to section 1-75(c) of the Illinois Power Agency Act. (Pub. Act 95-0481) AIU is free to inform and educate customers regarding these REC purchases.

AIU is welcome to provide additional details regarding Rider VGP and resubmit it for the Commission's review. To avoid the potential for customer confusion, however, AIU may want to consider ways to participate in the Chicago Climate Exchange, Acid Rain Program, or another emissions trading program. Such programs clearly do not involve purchasing electricity and have a definitive benefit of reducing airborne pollutants. To be clear, the Commission is not requiring AIU to make emissions allowances available for customers' purchase. The Commission is merely suggesting an alternative to Rider VGP that the AIU may want to consider. Like RECs, the trading of emissions allowances has environmental benefits. Emission allowances, however, may be easier for customers to understand. Additionally, while it does not appear to be the case, until a more complete Rider VGP (or some alternative) is put forth, the Commission will reserve judgment on whether such a rider constitutes a violation of Section 452.230.

VIII. COST ALLOCATION

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. Each of the three utilities currently divides retail electric customers into five rate classes. The DS-1 Residential Delivery Service rate class tariff contains meter, customer, and delivery charges for residential customers. The DS-2 Small General Delivery Service class tariff includes meter, customer, and delivery charges for non-residential customers with demands up to 150 kilowatts ("kW"). The DS-3 General Delivery Service class tariff includes meter, customer, delivery, and transformation charges for non-residential customers with demands equal to or greater than 150 kW but less than 1,000 kW. The DS-4 Large General Delivery Service class tariff includes meter, customer, delivery, transformation, and reactive demand charges for customers with demands exceeding 1,000 kW. The

DS-5 Lighting Service class tariff provides for street lighting and protective lighting service to customers. While similarities exist among the three utilities' current gas delivery service rate class tariffs, many differences remain. AIU has proposed revisions in this proceeding toward the goal of making the gas delivery service tariffs more uniform.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a cost of service study ("COSS"). A COSS compares the cost each customer class or subclass imposes on the utility's system to revenues produced by each class or subclass. A properly performed COSS shows the cost to serve each class or subclass and the ROR for each class or subclass. Customer classes or subclasses with a ROR equal to the total system ROR are paying their cost of service. Customer classes paying less than the total system ROR are not paying their cost of service. From time to time circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. Resolved Issues

1. Rate Classes

AIU proposes to maintain six general gas rate classes for each of the three gas utilities: (1) GDS-1 Residential Gas Delivery Service, (2) GDS-2 Small General Gas Delivery Service, (3) GDS-3 Intermediate General Gas Delivery Service, (4) GDS-4 Large General Gas Delivery Service, (5) GDS-5 Seasonal Gas Delivery Service, and (6) GDS-7 Special Contract Gas Delivery Service. AIU's only proposed change to the general rate classifications is to eliminate a rate class that only AmerenCILCO has: GDS-6 Large Volume Gas Delivery Service. AIU proposes to eliminate AmerenCILCO‘s GDS-6 tariff as a stand-alone rate class and modify AmerenCILCO‘s GDS-4 tariff to address the large usage customers. Staff recommends approval of AIU‘s proposal to eliminate AmerenCILCO‘s GDS-6 on a stand-alone basis. No other party comments on AIU‘s rate classification approach. The Commission finds the rate classification proposal reasonable and adopts it.

2. Billing Determinants

AIU proposes adjustments to the billing determinants used in the gas COSS and ratemaking. AIU recommends adjusting the existing non-residential customer billing determinants for the GDS-2, GDS-3, and GDS-4 classes for AmerenCILCO and AmerenCIPS to accommodate the revision to these two utilities' rate class availability provisions to match the AmerenIP class definitions. These adjustments anticipate the changes that would be necessary if AIU's contested reclassification proposal regarding the GDS-2, GDS-3, and GDS-4 classes is adopted. Staff agrees with AIU‘s proposed adjustment to the billing determinants assuming the reclassification of the GDS-2, GDS-

3, and GDS-4 classes. Although GFA recommends modifying AIU's proposed availability criteria regarding the GDS-2, GDS-3, and GDS-4 classes, it does not address AIU's billing determinants adjustments. No other party comments on AIU's billing determinants adjustments. Given the Commission's conclusion below regarding AIU's proposed availability terms for the GDS-2, GDS-3, and GDS-4 classes, AIU's billing determinants for the GDS-2, GDS-3, and GDS-4 classes for AmerenCILCO and AmerenCIPS are approved.

3. Weather Normalization

Regarding gas delivery service rates, the weather normalization analysis and adjustments proposed by AIU are uncontested. AIU prepared a detailed weather normalization analysis and proposes to use an average of 10 years annual HDD based on historical data from the Champaign-Urbana weather station. AIU utilizes this weather normalization analysis in the gas COSS and rate design to adjust the historic test year so that it represents typical or normal circumstances from an HDD perspective. Staff recommends that the Commission approve AIU's proposal. No other party commented on AIU's weather normalization approach. The Commission finds AIU's weather normalization analysis and adjustments reasonable and adopts them.

4. Account 904

AIU addressed net write-offs recorded in Account 904, Uncollectible Expenses, as part of its gas cost of service analysis. Staff pointed out that the net write-offs recorded in Account 904 had been allocated in the same percentage for each class in each of the three gas COSS. AIU responded that the AmerenIP allocation was correct, but that the initial Account 904 allocations were incorrect for AmerenCIPS and AmerenCILCO. AIU re-ran the gas COSS to quantify the impact of the oversight and provided updated COSS for AmerenCIPS and AmerenCILCO that corrected for the Account 904 allocation oversight. AIU states that while the class impacts of the updated COSS for AmerenCIPS and AmerenCILCO are de minimis, the results of the updated COSS should be factored into the final rate design approved by the Commission. Staff does not object to the corrections relating to Account 904. The Commission finds the corrections reasonable and accepts them.

B. Contested Electric Issues

1. Cost Allocation for Customers at 100+ kilovolts

Customers receiving service at 100+ kilovolts ("kV") in the DS-4 customer class essentially take service at a transmission voltage. Unlike AIU's other customer classes, the DS-4 customer class contains a relatively few customers with large electric demand. Additionally, these DS-4 customers often have multiple service points. They can own or rent substations or transformers, use AIU's substations or transformers, or use some combination thereof. AIU and IIEC disagree on the proper allocation of costs to such customers who make relatively little use of the distribution system.

a. AIU Position

In the current rate cases, AIU allocates costs to the DS-4 customer class using class demand studies different from those used in its prior rate cases. Previously, allocation factors were based on supply voltage alone. The allocation factors used in the current cases are based on a combination of supply and delivery voltage. This change in allocation factors increases the costs to be recovered from the DS-4 customer class.

IIEC acknowledges that 100+ kV DS-4 customers should pay something for their delivery service, however, it disagrees with AIU‘s allocation of costs to the customers that operate at the highest voltage level--100 kV or higher. IIEC specifically contends that customers taking service at a voltage above 100 kV do not receive any benefit from the portions of the distribution system that operate below the 100 kV level. AIU counters that IIEC fails to consider the new allocation factors reflecting delivery voltage. AIU explains that based on its voltage definitions, customers can be supplied via a substation feeder at one voltage level, but ultimately delivered at a lower voltage level. AIU adds that many customers supplied at 100+ kV use transformers and substations owned by AIU, and should not be able to bypass delivery service rate responsibility associated with use of the system. According to AIU, the current case‘s allocations are a better representation of cost causation due to the recognition of delivery voltage.

AIU contends that its transformation charge provides additional support for the proposition that customers can be supplied at one voltage but delivered at a lower voltage. More particularly, a customer will be billed a transformation charge to compensate AIU for providing transformation of voltage from the customer‘s supply voltage to the delivery voltage used by the customer. AIU maintains that costs are properly allocated to customers supplied at 100 kV and above, but delivered at lower voltages to match how AIU‘s assets are being used by customers.

Furthermore, AIU continues, if customers use their own transformers, those customers‘ demands are not included in the lower delivery voltage category. The same effect holds true for customers who rent transformers. AIU explains that those delivery voltage demands for customers who rent transformers are included and costs are appropriately allocated but revenues from rentals are included as an offset to the revenue requirement.

Additionally, AIU asserts that the DS-4 class represents only a small number of its customers and these few customers accept delivery service in differing configurations. There is, for instance, one customer that does not require transformation because that service is provided to a switchyard. There are three customers that own their transformers. Of the remaining customers, ten either rent or are charged for transformation service from AIU on their entire load and two customers receive transformation service on a portion of their load. All totaled, five customers do not take transformation service from AIU, and 12 customers do take transformation service from AIU.

AIU reminds the parties that a COSS will not always match costs, expenses, and miscellaneous revenues perfectly, since it allocates to all customer classes. AIU states that outliers in a COSS will always exist as uniform rates by class are produced. Outliers in customer classes with relatively few customers will be difficult to address. While AIU can refine its methodologies to be as accurate as possible, it avers that it is important to continue the practice of allocating costs at a class level rather than focusing on the particulars of individual customer cost causation. With the modification described above regarding FERC Account 362, AIU urges the Commission to accept its general approach for allocated costs to the 100+ kV class of customers.

b. IIEC

IIEC agrees that all customers should be allocated the costs of the distribution system that they use. IIEC adds, however, that it is of vital importance that AIU demonstrate that the customers do, in fact, use the subject facilities, and are therefore responsible for the facility costs allocated to them. Contrary to AIU's suggestion, IIEC does not claim that 100+ kV customers do not use transformers and substations owned by AIU. Nor does IIEC suggest that these customers should be able to by-pass delivery service rate responsibility associated with the use of such transformers. As AIU witness Althoff testified during cross-examination by Staff, the use of the "DDSUBTR" allocation factor does, in fact, allocate costs to customers supplied at 100+ kV. (See Tr. 609-610)

AIU also claims that IIEC's statements regarding the proper allocation of costs to customers that operate at the highest voltage level only considers the ―supply voltage" of these customers. IIEC notes that it has not disputed the difference between, or the importance of, supply, and delivery voltages. IIEC merely attempts to ensure that the costs of 34 kV and 69 kV substations are not misallocated to customers taking service at 100 kV and above. While IIEC believes that AIU must go to the next step and actually provide the Commission with the results of a corrected COSS, IIEC has not made any recommendations with regard to the use of supply or delivery voltages or disputed those differences in this case.

c. Commission Conclusion

For reasons that are not entirely clear, AIU modified the class demand study used in the COSS from its previous rate proceeding. As noted above, the allocation factors were previously based on supply voltage alone. The allocation factors used in the current cases are based on a combination of supply and delivery voltage. This new allocation factor results in an increase in the costs to be recovered from the DS-4 customer class.

Before the Commission consents to the use of the AIU's new allocator, it must be sure that the resulting allocations are appropriate. In other words, the Commission must try to ensure that costs are allocated to those who cause the cost. From the record, it is not clear that DS-4 customers receiving service at 100+ kV are using those portions of the distribution system associated with providing service at less than 100 kV, at least not in a way in which they are not already paying for it. AIU's new allocator in its demand study appears to unnecessarily shift costs to customers taking service at 100+ kV. Unless more persuasive evidence is provided in a future proceeding, AIU should return to using supply voltage alone.

2. Cost Allocation of Primary Distribution Lines and Substations

AIU's electric COSS uses the non-coincident peak ("NCP") allocator to allocate costs associated with primary distribution lines and substations among the rate classes. Staff, however, recommends that substation and primary line costs be allocated on a basis of coincident peak (–CP”) rather than NCP. The CP method allocates costs based on the demands of individual customers at the time of the overall system peak, while the NCP method allocates costs based on the demands of individual customers at the time of peak for the class. Under the NCP method, classes may experience their respective peak at different times of the day, which may or may not occur at the same time as the overall system peak. IIEC supports AIU's use of the NCP allocator.

a. Staff Position

Staff prefers the CP allocator over the NCP allocator because it does not believe that the latter accurately reflects how the costs of distribution lines and substations are incurred. Staff points out that the individual class demands do not necessarily shape the costs of primary distribution lines and substations which are generally constructed to serve the demands of multiple rate classes that collectively use those facilities. This is evident from AIU‘s own statements, Staff continues, acknowledging that distribution facilities are not designed based on rate classes, but instead are designed based on the aggregate load in a locale. Staff observes that AIU also concedes that for both distribution lines and substations specifically, it is reasonable to assume that they would serve multiple rate classes. Staff maintains that these admissions by AIU have direct implications for allocating primary distribution line and substation costs. If these facilities were to serve customers from a single rate class, Staff agrees that the peak demands of individual classes would determine their size and ultimate cost. But because that is not the case in most instances, Staff states that the design would have to take into account the combined CP demands of customers from all classes served.

Staff rejects AIU's argument that local demands (as cost drivers) justify the use of an NCP approach for primary lines and substations. Staff counters that neither a CP allocator nor an NCP allocator measures –local” demands. Each seeks to represent demands on a utility-wide basis. The key difference is that the CP reflects the collective demands of multiple rate classes while the NCP is based on the peak demands of individual rate classes. The issue for primary lines and substations concerns which of the two allocators reflects the collective peak demands of multiple rate classes at a local level. Since the CP focuses on multiple rate classes and the NCP on individual rate classes, Staff contends that the CP is the more cost-based approach.

Staff asserts that the DS-5 lighting class illustrates the shortcomings of an NCP allocator for primary distribution lines and substations. This class, which uses most of its electricity during off-peak, evening hours, is penalized in Staff's opinion by the NCP which factors those full off-peak demands into the development of the allocator. Those off-peak demands are used to allocate to lighting customers the costs of primary distribution lines and substations which AIU admits are designed based on the collective demands of ratepayers from all rate classes served at that locale. Staff maintains that this clearly conflicts with cost causation principles. Staff argues that the more equitable approach for lighting and other classes, as well, is to allocate primary distribution lines and substations according to CP demands. The individual class shares represent the contribution of each to this overall peak demand on the system. The CP is the allocator that most accurately represents the combined demands of multiple rate classes and is, therefore, most appropriate for distribution lines and substations that collectively serve customers from different classes.

AIU criticizes the CP approach for allocating ―zero costs" of primary lines and substations to DS-5 customers. Staff responds again that the issue here concerns causation and what allocation classes receive should reflect their contribution to these costs. If lighting customers use electricity when other classes use less, Staff asserts that their demands will not drive the causation of these costs. What AIU leaves unsaid, Staff continues, is that the NCP allocates primary line and substation costs to lighting customers based on their maximum demands which occur during off-peak hours. Staff maintains that it is patently unfair to give as much weight to these off-peak demands as for maximum demands by other classes that do coincide with the peak. Staff believes that it is clear that it is these latter demands, not lighting demands, that drive primary line and substation investments. Staff also notes that AIU states that while the NCP demand allocation may allocate too much to the DS-5 class, the CP demand allocation will allocate too little. (See Ameren Ex. 41.0 at 5) Staff finds this statement notable because it seems to acknowledge that the NCP allocates too much to the lighting class. Since the CP approach comports most closely with the way these costs are determined, Staff insists that that is the methodology that should be used.

Staff is also not persuaded by AIU's example using grain drying customers as support for the NCP approach. Specifically, AIU argues that a single CP allocator would fail to recognize that ―several circuits that serve grain drying customers in fact peak during the fall grain drying season." (Ameren Ex. 41.0 at 6) Staff finds this argument problematic. For one, AIU does not identify the circuits or provide a number to accompany the claim of ―several." This makes it difficult for Staff to determine whether these circuits comprise a significant share of the total investment in primary lines. Second, it is not clear to Staff why AIU is focusing on cost allocations to grain dryers since these customers do not constitute a separate class for allocating the cost of service. Instead, they constitute subclasses of the DS-3 and DS-4 classes and receive cost allocations in conjunction with all other customers within their class. Furthermore, Staff relates that the rate limiter in effect for grain dryers is not directly based on the cost of service, but rather is driven by bill impact concerns for a subgroup of DS-3 and DS-4 customers. Staff therefore concludes that grain dryers are not a relevant example for this cost of service issue.

AIU's argument that CP demands are not appropriate for allocating primary lines and substations to DS-3 and DS-4 customers is likewise dismissed by Staff. AIU contends that these classes —are not weather sensitive" and could peak during various times throughout the year. Since its CP occurs in the summer season reflecting the impact of weather, AIU considers the CP's failure to capture these off-peak DS-3 and DS-4 demands a problem. To the extent that demands by these customers take place during off-peak periods, Staff states that their contribution to investments in primary lines and substations will be reduced. Staff maintains that this off-peak usage should be rewarded, not punished, which would be the case under the CP rather than the NCP allocator.

Regarding AIU's discussion of the impact of using the CP allocator on each customer class, Staff asserts that such an argument does not belong in a discussion of cost allocation. Staff maintains that a COSS should allocate costs solely based on how classes cause those costs to be incurred. Only after costs are allocated and class revenue responsibility is determined does Staff believe that it is appropriate to consider bill impacts in the ratemaking process. Staff insists that injecting bill impacts into the cost allocation process makes it impossible to determine the real responsibility of customer classes for system costs. As a result, it will be that much more difficult to make an informed decision concerning the appropriate balance of costs and bill impacts in the ratemaking process.

IIEC also criticizes Staff's preference for the CP allocator. IIEC notes that there are conditions wherein the CP method fails to allocate costs to certain classes because, though they use the distribution system, they do not use electrical power at the time of the system peak demand. Staff finds IIEC's argument misplaced. For one, Staff states that it is not advocating the CP approach for all distribution costs, only those pertaining to primary lines and substations. Second, Staff asserts that the cost of service issue should not focus on the amount of costs the CP allocates to any individual class, but rather on whether that allocation most accurately reflects how costs are caused by AIU ratepayers. Staff relates that the NCP allocator is based on the sum of individual class demands based upon the separate peaks of each rate class. So, if one class uses less when the system peaks and uses more when overall demand is low, the NCP will allocate system costs to that class based upon its off-peak usage. The problem is that equipment such as primary lines and substations are generally constructed to serve multiple rate classes, not just one class at a time. Because the demands of multiple classes more closely correspond to CP rather than NCP demands, Staff insists that the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes.

b. AIU Position

In defense of its use of the NCP methodology, AIU observes that the Commission approved of its use in allocating distribution plant costs in AIU's prior delivery services rate orders. Continued use of NCP is fitting, according to AIU, because it more appropriately allocates costs to customers that cause the costs to arise since, on-balance, NCP demands more closely match the demands placed on local substation and primary line facilities. AIU agrees with Staff that its facilities are built to serve demands based on locality and that geographical locations do encompass customers in multiple rate classes. The fault in Staff's position, in AIU's opinion, is that Staff does not consider the fact that customers within these geographical locations can peak at various times throughout the year.

AIU states that Staff's focus appears to be on the "multiple rate classes" element of CP demand, ignoring the fact that CP demand is always less than the sum of the localized demands placed on distribution facilities. AIU indicates that local facilities such as substations and primary lines are not built and sized with this level of diversity in mind. Instead, AIU explains that distribution system planners look at the expected peak of customers connected to the facilities, whether they occur in summer, fall, winter, or spring. This is based on the fact that the collective peaks on individual systems are greater than the CP. AIU maintains that the NCP demand more closely matches the load diversity on these more localized systems.

AIU states further that the use of CP demand would not be beneficial to many of its customers. According to AIU, the use of CP would increase costs to the DS-1, DS-3, and DS-4 rate classes but would lower costs to the DS-2 and DS-5 classes for AmerenIP. For AmerenCIPS, the DS-3 and DS-5 classes would be allocated lower costs under the CP allocation; however, the DS-1, DS-2, and DS-4 customers' costs would increase. The affects for AmerenCILCO are that the DS-1 and DS-5 rate classes receive less costs utilizing CP while DS-2, DS-3, and DS-4's costs would be higher.

The notion that DS-5 customers should not bear any costs for substations or primary lines, since they peak during off-peak, evening hours, is also problematic for AIU. AIU states that lighting customers use primary lines and substations and should be allocated at least some costs for the use of these assets. To allocate zero substation and primary line costs to the DS-5 class is flatly incorrect.

AIU disagrees that the use of NCP "punishes" non-weather-sensitive customers, as Staff contends. Instead, AIU contends that it appropriately allocates the cost of facilities to match how the facilities were designed, built, and sized. CP, on the other hand, is a detriment to these rate classes, according to AIU. AIU maintains that allocating substations and primary lines based on CP is improper because it would fail to appropriately align costs with the cost causers for which the systems are designed and constructed. AIU argues that the use of NCP provides the most accurate methodology for allocating distribution assets to ensure that no customer rate class subsidization occurs.

With regard to GFA's seasonal pricing concerns and the allocation of primary lines and substation costs, AIU continues to believe that such seasonal rates for the DS-2, DS-3, and DS-4 classes will ultimately create a subsidy by non-seasonal customers. AIU nevertheless does not object to examining a sample of circuits serving the DS-3 and DS-4 in order to bring clarity to the debate in the next rate case. AIU acknowledges that such a review may lead to improvements in its COSS.

c. IIEC Position

IIEC opposes Staff's recommendation that the CP allocator be used to allocate costs of primary distribution lines and substations. Contrary to Staff's suggestions, IIEC argues that the NCP method reflects the collective demands of every rate class and, in certain instances, reflects the collective demands of more rate classes than does the CP method. IIEC contends that this point is best illustrated by Staff's discussion of how the NCP method penalizes the lighting class. Staff's discussion ignores the fact that in the AIU COSS, the CP method does not recognize that the DS-5 rate class has any demand whatsoever and allocates no costs for primary lines and substations to the DS-5 class. IIEC states that it is obviously necessary to use primary lines and substations to serve the DS-5 class. IIEC avers that an allocation method that results in this class being assigned none of the cost of those facilities is clearly an erroneous method. The NCP method, on the other hand, does not suffer from this deficiency and recognizes the collective demand of every rate class regardless of when it occurs, according to IIEC.

d. GFA Position

GFA agrees with AIU that substations and distribution lines are designed to serve the maximum demand expected on the facilities regardless of the season. GFA, however, is still interested in the possibility of seasonal class distribution rates. GFA recognizes that grain companies can contribute to significant loads on substations and primary lines, particularly in the fall. Of concern to GFA, however, is the fact that AIU has provided no system-wide seasonal load data for primary lines and substations, the costs of which are being allocated to each of the DS-2, DS-3, and DS-4 customer classes from which grain companies are served, along with many other users. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA opines that AIU's distribution system cost of service varies by season. This leads GFA to the conclusion that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. GFA has not requested a special rate for grain dryers. Rather, it is requesting that AIU begin collecting the necessary data to conduct analysis of prospective seasonal cost based rates for DS-2, DS-3, and DS-4 customers with regard to costs of primary lines and substations. While AIU continues to disagree with GFA's conclusion regarding seasonal pricing, GFA states that AIU concedes that the information requested by GFA could lead to more proper cost allocation and pricing, and has agreed to perform further study and provide the result in the next rate case.

e. Commission Conclusion

As with any cost allocation issue, the Commission's goal is to allocate costs to those customers who cause the costs. In this instance, the Commission must determine which allocation method, NCP or CP, best allocates the costs of primary distribution lines and substations. When constructing or expanding primary lines and substations, a utility considers what load those customers to be served by the facilities will impose on the facilities. In most situations, the facilities will serve customers from more than one customer class. The peak of each individual class to be served by the facilities is irrelevant. What is relevant is the combined or coincident peak of all of those served by the facilities, regardless of which class each customer is in. The utility therefore sizes and constructs primary lines and substations to accommodate the anticipated coincident peak.

Why the allocation of the costs of primary lines and substations should be considered differently is unclear to the Commission. Consistent with cost-causation principles, those customers imposing a demand on the facilities at the time of the coincident peak (which was the primary driver in determining the facility size) should be allocated a proportionate share of the costs. The Commission recognizes that under this analysis, DS-5 lighting customers, because they tend to have zero demand during the coincident peak, are not allocated any of the costs of primary lines and substations. In other words, DS-5 customers are not responsible for any of peak demand on primary lines and substations. Because, however, DS-5 customers are rarely, if ever, considered in sizing primary lines and substations, this result is not inappropriate. This is not to suggest that DS-5 customers should not be expected to pay for distribution service. DS-5 customers' delivery service charges will consist of costs for facilities and services other than primary lines and substations. Because the demands of multiple classes on primary lines and substations more closely correspond to CP rather than NCP demands, the Commission agrees with Staff that the most reasonable, cost-based approach is to allocate the cost of this equipment according to the collective peak demands of all rate classes.

AIU's discussion of impacts on customers from using the CP allocator is misplaced. As Staff indicates, the underlying goal of any COSS is to allocate costs to those customers who cause the costs to be incurred. While rate impacts are of concern, the appropriate time to consider rate impacts is after costs have been allocated. At that time, rate mitigation efforts could be used to address any unreasonable or inappropriate rate impacts. In addition, that IIEC would oppose an allocator that shifts costs to larger customers comes as no surprise to the Commission. But given IIEC's concerns about assigning costs to cost-causers, the Commission finds IIEC's position on this issue somewhat inconsistent.

3. Allocation of Electric Distribution PURA Tax

Following the 1970 elimination of the Personal Property Tax, Illinois utilities became subject to a tax on invested capital, pursuant to the PURA. Prior to 1998 for electric utilities, the tax was assessed at a rate of 0.8% of the utility's invested capital. In conjunction with the electric restructuring legislation adopted in 1997, Illinois revised the PURA to impose a per kWh tax on electricity distribution by electric public utilities, rather than a tax on invested capital. AIU proposes that the electric distribution tax be allocated and collected from customers based on kWh sales as well. IIEC opposes that proposition and, instead, contends that the tax should be allocated on a demand basis, using the manner in which the tax was assessed and collected before the 1997 revisions to the PURA. Staff supports AIU's proposal.

a. IIEC Position

In support of its position, IIEC asserts that when Illinois restructured the electric utility industry, it also determined that it would change the basis of the PURA tax to keep it competitively neutral, while maintaining essentially the same level of tax revenues from each of the Illinois utilities individually and in the aggregate, through a series of charges designed to be applied to each utility's delivered energy. IIEC contends that this design protected the tax revenue stream from variation due to utility sale or transfer of generating or transmission assets, since such sale had the potential to reduce a utility's level of invested capital and thus its tax liability. In 1997, the level of tax on invested capital for the three utilities was about $4 million for CILCO, $9 million for CIPS (including the former Union Electric Company), and $23 million for IP.

As a protection for utilities and their customers, IIEC states that the aggregate level of electric PURA tax that the state could collect was capped at $145,279,553 in 1998, adjusted for growth in subsequent years at the lesser of 5% or the percentage increase in the CPI. IIEC reports that the cap has been exceeded every year from 1997 through 2007, prompting annual proportional refunds. IIEC expects that this is likely to be the case for the foreseeable future.

Traditionally, the PURA tax imposed on the utilities has been considered a recoverable test year expense and has been allocated among the rate classes in the COSS based on the classes' share of the cost of utility plant in service, since plant in service represented the capital investments of the utilities. Although the PURA tax was restructured in 1997, IIEC relates that in each of the delivery service rate cases initiated by AIU or their unaffiliated predecessors since 1997 (12 cases in all) the PURA tax has been allocated on the basis of plant in service. As indicated above, however, in the current case AIU proposes to change its allocation from one based on plant in service to one based on the number of kWh delivered to each class. IIEC complains that this proposal would have the effect of shifting millions of dollars of revenue responsibility from the small customer classes to the large customer classes. IIEC asserts that the change in allocation accounts for much of the large increases in delivery service charges proposed by AIU for the DS-4 customers, particularly those taking service at higher voltages.

IIEC opposes AIU's proposed change in the allocation of the PURA tax for four primary reasons. First, IIEC claims that AIU has not justified changing the PURA tax allocation method. In response to discovery requests from IIEC, AIU indicates that it does not have any documents regarding its determination that the traditional approach is no longer appropriate. According to IIEC, AIU's entire rationale for the change is that the annual tax is assessed to AIU based on the quantity of retail electricity delivered in Illinois, making it clearly driven by kWh sales and not based on plant assets. (See Ameren Ex. 16.0E Second Revised at 8)

In response, IIEC argues that kWh sales are only one of several factors, and not the main factor, that determine a utility's PURA tax responsibility in any given year. IIEC insists that the main factor determining a utility's PURA tax responsibility today is the utility's 1997 level of invested capital (and associated tax). The tier levels and tier rates in the PURA, IIEC continues, were custom-designed to approximate the same level of total tax revenue from all utilities and the proportion of tax paid by each utility, as the utilities paid based on their invested capital. IIEC contends that AIU's allocation of the PURA tax on the basis of energy delivered actually moves rate making away from cost causation, giving more weight to the words used to describe or compute the tax than to the actual causes of the tax assessed. IIEC maintains that AIU's proposal to change the only allocation basis it has ever used without any evidence of a change in cost causation and without any quantitative evidence of causation for kWh delivered is not consistent with cost causation principles or AIU's obligation to demonstrate that the change is just and reasonable.

Second, contrary to AIU's and Staff's suggestion, IIEC states that any correlation between kWh sales and the utilities' PURA tax liability in a given year is very weak--at least that is what IIEC says it found when it analyzed the actual kWh sales reported by AIU and the actual PURA tax payments. IIEC witness Stephens explains that if the level of usage determines the amount of PURA taxes, one would expect a linear positive relationship between the PURA tax and kWh deliveries, with the slope of the line representing the marginal (last block) tax rate. The actual AIU data, however, indicates a very weak explanative value of kWh deliveries for changes in the PURA tax, according to Mr. Stephens. He notes further that the slopes of the regressed lines are different from the applicable marginal tax rates set forth in the 1997 legislation. That is, the PURA taxes that a utility pays and kWh the utility delivers change at different rates. Mr. Stephens states that this is another indicator of lack of correlation between the kWh sales and expected tax levels. IIEC asserts that its analytic evidence was unrebutted by AIU or Staff, who rely instead on the simplistic, erroneous assertions that kWh sales drive or cause the utilities' PURA tax liability, without conducting any investigations of the actual cause of the tax liability incurred by the utility.

Third, IIEC maintains that the large majority of the current PURA tax is simply inherited 1997 invested capital tax. IIEC states that approximately 84% of the PURA tax assessed to AIU in 2008 was attributable directly to the 1997 invested capital taxes. Given the Commission's commitment to cost causation principles in setting rates, IIEC contends that it would be unreasonable and unfair to allocate the PURA tax entirely on the basis of energy usage, when nearly 84% of the tax is caused by historical utility plant investment unrelated to energy delivery. Furthermore, IIEC asserts that even the growth in tax liability post-1997 is closely tied to 1997 invested capital levels, through the utility-specific tax rates. IIEC insists that there is virtually no evidence to compel a change in the allocation of this significant cost item.

Fourth, IIEC argues that AIU's proposed allocation of the PURA tax is not consistent with the legislature's desire to maintain the 1997 invested capital tax levels and utility shares. IIEC states that Section 1a of the PURA describes the legislative intent of the statute. According to IIEC, the legislative intent clearly indicates that the legislature had two goals in mind: 1) to assess the tax in a way that would be fair, as between utilities and other energy suppliers in the restructured industry, and 2) to maintain tax levels, with comparable allocations among the utilities. IIEC states that no where in the law is there expressed an expectation that the redesign could shift tax burdens from one customer class to another.

With regard to the legislature's first purpose, IIEC explains that it was necessary to change the collection basis from utility invested capital to delivered kWh because the restructuring law paved the way for new electric suppliers who would not be utilities under applicable law. These new suppliers would not be regulated by the Commission, and might not own physical assets. The new suppliers would enter the Illinois market to compete against utilities or other suppliers that would have been subject to the invested capital tax. Moreover, IIEC continues, the 1997 restructuring law allowed utilities to sell or transfer capital assets to affiliated or unaffiliated third parties, with very limited Commission oversight. Thus, IIEC concludes, converting the form of the tax to a delivered energy calculation and collecting it only from the regulated delivery utilities leveled the playing field among competing suppliers.

With regard to the legislature's second purpose, IIEC states that the structure of the statute indicates that the legislature wished to maintain tax revenues comparable to the amount collected before the change in the law. Since the invested capital of the utilities in 1997 caused a specific level of PURA tax for each utility, IIEC states that it would not have mattered whether the legislation achieved its revenue neutrality by replicating the amount using a calculation based on per kWh rates or by simply enumerating each utility's starting tax level in the law. IIEC asserts that the same level of tax could be derived under any number of custom approaches; the Illinois Legislature happened to use the custom-designed per kWh approach. IIEC contends that the approach chosen by the legislature simply to maintain tax revenue stability does not dictate a shift in cost responsibilities among customer classes.

IIEC acknowledges that the Commission did approve an allocation based on kWh delivered in the initial ComEd delivery service rate case. (Docket No. 99-0117, August 26, 1999, Order at 40) IIEC suggests that the Commission did not, at that time, have the breadth of information on the tax, its cause, and the lack of correlation between kWh delivered and the amount of the tax that is contained in the record in this case. IIEC therefore believes that this record is distinguishable and requires a different result from that in the ComEd proceeding.

If none of its arguments persuade the Commission to retain the traditional allocation of the PURA tax, IIEC offers an alternative tax allocation method which it believes even more precisely allocates tax costs to cost causers. IIEC proposes that the Commission recognize the distinctive cost-causation of portions of the PURA tax by creating two separate cost categories for the tax in the COSS, with different allocation factors for each. The first cost category would be the 1997 levels of PURA tax for each utility. This cost category should be allocated on the traditional basis of utility plant in service. The cost should be recovered in the distribution delivery charge, as is currently the case. The second category of costs would reflect PURA tax amounts in excess of the 1997 levels. These are subject to increase over time as the PURA tax level grows with the escalators on the statewide cap. Under IIEC's alternative proposal, this second category of PURA tax, the —post-1997 PURA tax" could be allocated based on kWh sales, in recognition that kWh sales may, under some circumstances and in some years, be a contributing factor to PURA tax levels. The 1997 PURA tax and the increases in post-1997 PURA tax levels for each of the three utilities necessary for implementation of this approach are shown in Table 1 of IIEC Ex. 5.0 Corrected at 14-15. IIEC computed revised cost of service results based on this alternative approach and provided them in IIEC Ex. 5.2. IIEC believes that this alternative approach provides a reasonable and practical compromise position on this contentious issue, should the Commission seek such a compromise.

b. AIU Position

AIU maintains that IIEC's approach is inappropriate because the structure of the tax is such that as a utility delivers more or less energy, the amount of tax will increase or decrease, all other things constant. Such a result indicates that plant is not a determining factor of the tax amount, but rather that the amount of kWh delivered is determinative. AIU states further that the difference between AIU today and CILCO, CIPS, and IP in 1997 is that in 1997 each of the utilities owned its own generation facilities that were part of the utility plant in service and provided fully bundled electric service. AIU insists that allocating and assigning the cost based on kWh is far superior to allocating the tax based on costs that no longer include generation plant. AIU adds that its proposal to collect the electric distribution tax based on kWh sales is consistent with the legislative intent of the law. Accordingly, AIU urges the Commission to adopt its kWh-based proposal.

c. Staff Position

Staff maintains that AIU's proposal to allocate the PURA tax by usage is consistent with cost causation and should be adopted in this proceeding. Staff observes that since the 1997 revisions to the PURA, usage has determined the amount of distribution taxes collected from ratepayers. Since usage is the driver, Staff states that cost causation principles would argue for allocating these costs on a per kWh basis. Section 1a of the PURA clearly shows, according to Staff, that the legislature made a conscious decision to change the way the distribution tax is determined, from a tax based on invested capital to a tax determined by usage.

The proposal to change from a plant allocator to a usage allocator would shift responsibility for these tax costs from smaller to larger customers on the system. Staff relates that large DS-4 customers account for 43% of system usage and, therefore, would be allocated 43% of these costs in contrast to the 8% they now pay. Staff states further that the allocation to residential DS-1 customers would decline from 56% to 30% of these costs.

Staff notes that the Commission has a longstanding goal of basing rates on cost. Staff contends that IIEC's argument is flawed because cost causation, rather than precedent, should be the deciding factor in the allocation process. If an existing method of allocating a cost that the Commission has approved is not cost based, then the most equitable and efficient solution is to adopt a cost based approach.

Staff rejects IIEC's argument that the continued allocation of distribution taxes according to plant in service is justified on cost principles. Staff also denies that the current level of the tax is primarily a function of the past levels of plant assets, as IIEC contends. While the starting point for the tax levels after the amendatory act corresponded to previous tax levels that were based on invested capital, Staff asserts that the yearly changes for taxes as a whole for all Illinois utilities are not. Staff observes that each year the total amount of distribution taxes collected by utilities increases by the lesser of 5% over the existing level or by the yearly CPI. Neither of these factors, Staff points out, bears any relationship to plant investments.

Furthermore, Staff continues, plant in service is no longer considered in the calculation. 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, Staff observes that the level of deliveries by electric utilities directly affects distribution taxes. If a utility‘s level of deliveries increases 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. Staff believes that it is clear that usage is the driver now.

There is no doubt that the legislature initially set the level of PURA taxes for each utility calculated on a usage basis approximately equal to the level under the previous plant-based method. Staff asserts, however, that the legislature made it explicitly clear that this tiered method of allocating PURA taxes to utilities would be based on a going-forward basis according to usage, not plant. There is no ambiguity in Staff's opinion that the legislature intended to replace the invested capital tax on electric public utilities with a new tax based on the quantity of electricity that is delivered. Staff notes further that the PURA goes on to state that this usage-based approach is fairer and more equitable.

Staff goes on to suggest that the continued allocation of these costs by the plant in service method directly conflicts with the intent of the law.

d. GFA Position

GFA expresses concern over the impact on larger customer's bills that collecting the PURA tax on a per kWh basis may produce. If the Commission adopts the AIU/Staff proposal for recovering the PURA tax, GFA respectfully suggests that the Commission consider alternatives that would mitigate some of that bill impact.

e. Commission Conclusion

At the outset, the Commission recognizes that allocation of the PURA tax among the electric rate classes involves millions of dollars. Properly assigning these tax costs to the cost causers is clearly important to both customers and the Commission. What drives these tax costs, however, is not entirely clear. IIEC makes interesting arguments in support of its position that invested capital (or plant in service), and not kWh, is the primary cost causer in this instance. IIEC relies on the fact that prior to 1997 plant in service was the basis for the PURA tax. IIIEC maintains that the legislature did not intend to alter this approach when it amended the PURA in 1997.

AIU, Staff, and IIEC each make compelling arguments for and against allocating the PURA tax on the basis of either plant in service or kWh. To resolve these competing concerns, a review of the PURA is necessary. Section 1a of the PURA addresses legislative intent and provides as follows:

> The General Assembly previously imposed a tax on the invested capital of electric utilities to replace in part the personal property tax that was abolished by the Illinois Constitution of 1970. Subsequent to the enactment and imposition of the invested capital tax on electric utilities, State and federal laws regulating the provision of electricity have been enacted which provide for the restructuring of the electric power industry into a competitive industry. In response to this restructuring, this amendatory Act of 1997 is intended to provide for a replacement for the invested capital tax on electric utilities, other than electric cooperatives, and replace it with a new tax based on the quantity of electricity that is delivered in this State. The General Assembly finds and declares that this new tax is a fairer and more equitable means to replace that portion of the personal property tax that was abolished by the Illinois Constitution of 1970 and previously replaced by the invested capital tax on electric utilities, while maintaining a comparable allocation among electric utilities in this State for payment of taxes imposed to replace the personal property tax.
> (Source: Pub. Act 90‑561, eff. Jan 1, 1998.)

This section leaves no doubt that the legislature intended to replace the invested capital/plant in service tax with a kWh tax in response to the changing nature of the Illinois electric utility industry. Also apparent from this language is that the legislature did not want to lose any tax revenue as a result of this change. What remains unclear to the Commission, despite IIEC's assurances, is that the legislature did not intend for any change in how a utility's PURA tax liability is allocated to customers.

While it is true that the statutory language does not expressly direct that the manner in which the tax is allocated be changed, the language also does not require that the allocation method remain the same. The Commission notes that shortly after the revisions to the PURA took effect, it approved allocating the PURA tax on a kWh basis for ComEd in Docket No. 99-0117. Either ComEd's current allocation approach is appropriate or it has been contrary to the legislative intent behind the PURA revisions for nearly 11 years. If the former characterization is accurate, and AIU has been allocating the PURA tax contrary to the legislative intent, nothing prevents the Commission from correcting such an oversight in this proceeding.

In resolving this issue, the Commission notes that the legislature clearly contemplated that regulated electric public utilities might shed much of their plant in service (primarily generation assets) and become regulated distribution utilities. Hence, the need to modify how the PURA tax was assessed. The possibility that the legislature contemplated has occurred, and much of that plant in service is no longer owned by the regulated electric utilities. The disconnect between plant in service and the distribution tax under the current PURA provisions is apparent from the fact that as the level of a utility's plant increases or decreases, that specific change would have no impact on the utility‘s distribution tax. A break from historic plant in service is also suggested in Section 2a.1 of the PURA, which imposes an annual cap on the aggregate amount of the distribution tax which can be collected statewide from electric public utilities and ARES, as those terms are defined in the Act. As a practical matter, no ARES deliver electricity. But if one ever did using its own plant in service, it would have no historic invested capital value for the legislature to try to preserve through the per kWh tax rates in the PURA.

For these and the foregoing reasons, the Commission is inclined to find the interpretation of the PURA by AIU and Staff more reasonable than that of IIEC. Adoption of the AIU and Staff position is also consistent with Docket No. 99-0117. If the legislature intended a different result, the Commission would welcome any such clarification. In the absence of any clear legislative intent to the contrary, AIU should recover PURA tax costs in base rates through the kWh-based Distribution Delivery Charge from the DS-1, DS-2, and DS-5 classes. AIU should create a kWh charge to reflect the PURA tax allocation that applies to the DS-3 and DS-4 classes.

4. Overall Suitability of AIU's COSS

AIU presented a separate electric COSS for each of the three utilities using a test year of 12 months ending on December 31, 2008. AIU's proposes rates based on the

COSS. IIEC contends that AIU's electric COSS are riddled with errors and should not be relied upon. Instead, IIEC recommends that the Commission allocate any rate change approved in this docket on an equal percentage, across-the-board basis. Staff generally supports AIU's electric COSS (but recommends specific revisions discussed below).

In Docket 07-0585, the Commission directed AIU to take into account alternative rate structures for the heavily subsidized all-electric residential customer sub-class that would incorporate the effect of innovative market-based dynamic or real-time pricing rate structures for retail all-electric customers. AIU was also directed to develop a separate sub-class for the residential space-heat customers and consider the use of a straight-fixed-variable rate design for this sub-class of customers if a dynamic pricing rate design utilizing market-based rates can be shown to be beneficial. 07-0585 Order at 281-282.

a. AIU Position

AIU explains that the class COSS presented in these cases are the result of the process of allocating and assigning the various cost elements of providing electric delivery service to the various customer classes in a way that best reflects the manner in which such costs are incurred in providing delivery service. The results of the class COSS are often referred to as the ―class revenue requirements." AIU identifies three steps in preparing a COSS: functionalization, classification, and allocation. Functionalization is the assignment of rate base items and operating expenses to major functions such as production, transmission, distribution, and customer service. Classification is the assignment of the functionalized costs to categories of cost causation. For example, costs may be classified as demand-related, energy-related, or customer-related. Allocation is the process of assigning the classified costs to the various classes of service.

With specific regard to the classification step, AIU states that it classifies each rate base and expense item in the electric delivery revenue requirement on the basis of cost causation to demand-subtransmission, demand-distribution, or customer. Demand-subtransmission and demand-distribution costs, AIU continues, are those investments and expense items that are incurred to meet system peak load requirements and local maximum demands, respectively. AIU relates further that customer-related costs are those investments and expense items which are incurred to serve customers and which do not vary with changes in consumption, such as the cost of the customer's meter and service drop.

In the development of distribution plant in the COSS model, AIU explains that the capital asset costs are segregated according to voltage level. AIU indicates that demand-related costs were allocated to customer classes based on the contribution of each customer class to the system's NCP demand based on the costs at the various voltage levels.

AIU asserts that its COSS preparation methodologies were approved by the Commission in its Order in Docket Nos. 06-0070 et al. (Cons.), AIU's second most recent electric delivery service rate proceeding. AIU notes, however, that some allocation factors were modified to more appropriately follow current operations and customer demand. Ameren Ex. 17.0 contains a discussion of AIU's allocation methodologies.

After reviewing the other parties' positions, AIU identified one necessary change to the COSS. Specifically, AIU realizes that the allocator used to determine how FERC Account 362 (reflecting costs for distribution substations) is allocated to customers was initially incorrect. AIU now agrees with IIEC that the DDSUBTR allocator should be used to allocate the costs in FERC Account 362. AIU explains that the DDSUBTR allocator is more appropriate because it selectively allocates the costs in Account 362 to customers with delivery voltage less than 100 kV. AIU adds that the change to the DDSUBTR allocator is proper because it more closely matches the function of the substations – lowering the supply voltage down to delivery voltage. According to AIU, adoption of the DDSUBTR allocator results in the reallocation of approximately $25 million to the DS-4 100+ kV customer subclass, out of $4.3 billion in total AIU allocable gross distribution plant. AIU states that the $27 million value cited by IIEC is a gross number before depreciation is applied, and ultimately translates into a revenue requirement reallocation totaling approximately $4 million (calculated as ROR multiplied by cumulative depreciation, less allocation depreciation, plus allocation depreciation expense) of associated revenue requirement to the DS-4 100+ kV customer subclass. The practical effect is that the revenue requirement reallocation will not reach $4 million if the Commission approves a revenue requirement lower than what AIU requests.

Even with the correction regarding the DDSUBTR allocator, AIU does not assert that its COSS are perfect. AIU acknowledges that assigning specific costs to broad rate classifications involves some subjective consideration, which includes some degree of generalized application and educated assumption. Regardless, AIU maintains that it is the steward of the COSS it maintains. AIU indicates that it is always willing to redress legitimate concerns regarding the study, as well as any similar models offered by Staff and customers. AIU is confident that its COSS presents a highly accurate allocation of cost causation. AIU states that it will continue to address stakeholder recommendations that could enable it to allocate costs more precisely in future rate cases. AIU urges the Commission to accept its COSS in this proceeding. To the extent that modifications have been proposed in this case, AIU asks that the Commission refrain from rejecting its COSS and instead direct that such modifications be implemented in future COSS.

Regarding the errors in the AIU COSS that IIEC claims to have identified, AIU points out that IIEC nevertheless used AIU's study rather then create its own. Concerning IIEC's allegation that AIU misallocates the PURA tax, AIU insists that its allocation is consistent with the statutory assessment of the tax. AIU also denies that its use of the NCP demand allocator is inappropriate. AIU maintains that IIEC provides little more than conclusory assumptions and generalized criticism of the NCP allocator that is unsupported by the record. As an example, AIU points to IIEC's claim that AIU fails to allocate the costs of poles, wires, and substations to nearly 2,000 large customers taking service at secondary voltage. AIU contends that IIEC cites no evidence to support this assertion. As for the allegedly ambiguous voltage definitions which IIEC complains of, AIU asserts that this is merely another iteration of IIEC's misplaced argument that AIU's use of both supply and delivery voltages in the cost allocations for large (100+ kV) customers is inappropriate. AIU also asserts that it provided responses to all of IIEC's discovery requests in a timely manner.

With respect to IIEC's complaints regarding allocation of transformer revenue, AIU argues that its approach is reasonable. AIU explains that transformer rental revenue, like other forms of revenue, is an off-set to the overall revenue requirement—which AIU states it recognized when it allocated that revenue in the COSS. Although IIEC contends that AIU has misallocated transformer rental revenue, it presents no alternative approach. If IIEC had proposed an alternate approach, AIU states that it would have considered it. Instead, IIEC merely reiterates its argument that AIU's COSS are not perfect, and as a result, the Commission should reject them in their entirety.

In response to IIEC's claim that the COSS reflect a discrepancy in the number of DS-2 customers, AIU contends that IIEC misinterprets AIU witness Althoff's testimony, as well as the data in Schedule E-6. During Ms. Althoff's cross-examination, AIU relates that IIEC displayed certain customer count statistics on the E-6 schedule. AIU asserts, however, that those statistics are unrelated to the metered delivery points utilized in AIU's COSS. Ms. Althoff noted during her examination that there are various customer count and delivery service point metrics, many of which are related to one another to some extent. AIU maintains that minor differences among these statistics are not indicative of underlying problems with the data it used in the COSS. AIU states further that it used customer count data by class to allocate certain costs, and NCP demand to allocate others. To the extent that the IIEC is suggesting differences between customer counts, meters, and delivery points are indicative of missing information, AIU contends that IIEC is simply presenting an apples-to-oranges comparison.

Because of the errors that it perceives in AIU's electric COSS, IIEC recommends that the Commission revise rates on an across-the-board basis rather than rely on the allegedly faulty COSS. AIU takes exception to this proposal and notes that IIEC advocates this position for the first time in its Initial Brief. AIU also points out that in AIU's last rate proceeding, Docket Nos. 07-0585 et al (Cons.), IIEC was steadfast in its support of cost based rates and openly criticized AIU for proposing an across-the-board increase in rates.

AIU notes further that during the course of the hearing, IIEC raised the notion of rerunning the COSS. AIU contends that this would not be a useful exercise and would not benefit the Commission's consideration of the issues in this case. According to AIU, utilities do not typically completely rerun a COSS during a rate case. Expanding the evidentiary phase of the case, AIU adds, only prolongs and complicates an already arduous process. AIU asserts that the COSS is merely a foundational step that is only conducted to provide support for its ultimate rate design recommendations. Absent the rate design considerations it is intended to support, AIU contends that a COSS update would not provide any additional analytical value. The revenue requirement values entered into the COSS at the beginning of the case will change as a result of the Commission's decision in these cases. AIU maintains that conforming the rate design to the final revenue requirement, both at aggregate and class levels, should not be addressed by reopening the evidentiary record. Instead, AIU believes that the final revenue requirement is more properly addressed by reference to witness testimony specific to that very subject. In this instance, AIU states that AIU witness Jones and Staff witness Lazare have offered testimony with regard to the methodology utilized to adjust proposed rates to the final revenue requirement.

To comply with the directive from Docket 07-0585, AIU performed an analysis to determine if marginal prices for the all-electric residential customer sub-class were competitive with market prices for power and energy. Results of this study show that with the subsidy that remains to this sub-class there continues to be a disparity in pricing by comparing marginal prices with market prices. (AIU Ex. 16.0E at 22)

b. IIEC Position

IIEC's criticism of AIU's electric COSS begins with the observation that the results of any COSS are only as valid as the inputs and assumptions used to develop the study. In this instance, IIEC contends that AIU's COSS contain errors in logic and factual inconsistencies that render them deficient for the purpose of setting rates in this proceeding. IIEC asserts that some of these errors and inconsistencies were identified in its written direct and rebuttal testimonies, while others were identified through cross-examination. In its direct testimony, IIEC claims to have identified (1) the misallocation of the cost of 34.5 kV and 69 kV substations (in FERC Account 362) to customers taking services at a voltage of 100 kV or higher, (2) the misallocation of PURA taxes, (3) errors in the development of the NCP demand allocators, and (4) a failure to properly allocate transformer rental revenue.

Regarding the alleged misallocation of the cost of 34.5 kV and 69 kV substations, IIEC claims that the AIU COSS allocated these sub-transmission costs to transmission level customer classes that take service at 100 kV or higher. IIEC suggests that in total, AIU's COSS improperly allocated $27 million in primary voltage and/or sub-transmission voltage substation equipment costs to transmission level customers. IIEC points out that the misallocation of these costs appeared to be associated with a change in the allocation factor used to distribute sub-transmission station equipment in the current studies. In the current studies, AIU used a factor identified as "DEMSUBTR." IIEC observes that in its prior COSS AIU used the DDSUBTR allocator, which IIEC believes properly allocates sub-transmission substation costs. Although AIU eventually agreed with IIEC that use of the DEMSUBTR allocator was an error, IIEC notes that AIU's acquiescence does nothing to remedy the COSS at issue which incorporates the DEMSUBTR allocator.

As for the new demand study component of AIU's COSS, IIEC understands AIU to believe that its new studies are more reflective of the demand incurred on the secondary voltage portion of its distribution system with respect to the DS-2 class. IIEC, however, contends that the new study actually results in the allocation of costs used to serve customers at secondary voltage levels to customers who do not use the secondary system. Specifically, IIEC states that the study does not distinguish between DS-2 customers taking service at primary voltage and DS-2 customers taking service at secondary voltage. Therefore, IIEC argues that it is difficult to see how the new study is more reflective of demand incurred on the secondary voltage portion of the system with respect to the DS-2 class if it attributes secondary system costs to customers who do not use that system. IIEC also fears that AIU has not properly counted the number of DS-2 customers.

IIEC further complains that AIU's COSS for AmerenIP does not allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to 1,936 DS-3a, DS-3b, and DS-4 secondary customers. IIEC contends that a similar situation occurs in the AmerenCIPS and the AmerenCILCO COSS. IIEC acknowledges AIU's suggestion that because these DS-3a, DS-3b, and DS-4 secondary customers are really supplied at primary voltage, the costs reflected in Accounts 362, 364, 365, and 366 would not be assigned to these customers. In IIEC's view, however, AIU's response calls into question class definitions in the AIU COSS. If classes clearly identified in the study as —secondary” are, in fact, supplied at primary voltage levels, IIEC does not understand how one can possibly determine, based on the COSS, whether secondary and primary costs have been properly allocated.

IIEC is also troubled by the testimony of AIU witness Althoff at the evidentiary hearing that the term —secondary” for the DS-3a secondary, DS-3b secondary, and DS-4 secondary classes refers to "metered voltage," and are totally separate and different from supply voltage and delivery voltage as AIU has used those terms in this case. (See Tr. at 586-587) IIEC states that AIU does not explain the significance of the term —metered voltage” in its description of its COSS. According to IIEC, Ms. Althoff's cross-examination testimony conflicts with her prepared written testimony wherein she stated that all customers have a supply and delivery voltage, where the supply voltage is the voltage of the feeder line from which the customer is supplied, and delivery voltage is the voltage at the point of connection between the customer's facilities and the AIU facilities. (Ameren Ex. 41.0 at 7) Under the circumstances, IIEC contends that it is difficult to see how the Commission can determine whether or not the AIU COSS in this case have properly identified the cost of serving these customer classes.

With regard to the assignment of transformer rental revenues, IIEC claims to have identified an error in the way AIU's COSS credited transformer rental revenues to the customer classes. AIU agrees that the revenues in question should be credited as closely as possible to the classes from which those revenues are collected. In the AIU COSS, however, IIEC notes that the transformer revenues were allocated on the basis of each class' contribution to NCP demand as determined by the new demand studies.

As a result of AIU‘s improper treatment of rental revenues, IIEC contends that customer classes from which rental revenues are collected do not receive the full credit of that revenue. This in turn, IIEC continues, understates the rate or return developed in the COSS for the customer classes that contributed to the rental fees. At the same time, the customer classes with relatively large contributions to peak demand are credited with a relatively large portion of the rental revenues, irrespective of the amount of rental revenues actually contributed by those classes. Although AIU has expressed a willingness to correct this error in the next rate case, IIEC asserts that waiting until then does little to help determine the cost of serving these classes in this case.

IIEC states that it re-ran the AIU COSS to correct for the first two deficiencies. The correction of these two deficiencies alone, IIEC avers, had a significant impact on the class rates of return and the revenue allocations in each of the COSS. As an example, IIEC states under the revised COSS, the DS-4 class as a whole provided higher rates of return than AIU‘s original studies suggested and that the DS-4 100 kV and above subclass provided rates of return significantly above the total rates of return for each of the three utilities. IIEC indicates that it did not receive the data it needed to modify the NCP demand data allocators from AIU in a timely manner, and was therefore, unable to correct the third deficiency in the COSS.

When all of these errors and inconsistencies are considered, IIEC argues that the fundamental validity and accuracy of AIU's COSS are called into question. Unfortunately, IIEC continues, analyses or alternate versions of the COSS, such as its own, that are based on AIU‘s flawed COSS are themselves flawed (although perhaps to a lesser degree). Under the circumstances, IIEC asserts that the Commission can not be sure that the costs of serving the classes and subclasses within each of the three utilities have been accurately and properly determined. Therefore, it is IIEC‘s primary recommendation in this case that the Commission reject the use of AIU's COSS for revenue allocation and rate design purposes, and allocate any increase authorized in this case on an equal percentage across-the-board basis. At a minimum, if the Commission decides to use AIU's COSS for rate design and revenue allocation purposes, IIEC urges the Commission to correct the COSS for at least the deficiencies IIEC identifies.

c. Staff Position

Staff contends that the fact that only AIU offered a COSS does not mean that AIU's arguments on related issues should carry more weight. Staff points out that utilities are required to provide such studies under Part 285. Moreover, Staff continues, utilities are typically the source of COSS in rate cases because it is their overall costs that are being allocated among customer classes. Staff adds, however, that there is no guarantee that a utility's COSS is accurate. As an example of inaccuracies in COSS, Staff notes that AIU proposes to change the allocation of PURA taxes in this case as a delayed reaction to legislation passed in 1997. Thus, Staff reasons, AIU's action in this case corrects an inappropriate allocator from previous cases. Staff notes that AIU also accepts a revised allocator for Account 362. Staff contends that these are not the only shortcomings with AIU's COSS, noting its arguments regarding the allocation of primary lines and substations costs. Staff maintains that each cost of service argument should be assessed on its own merits and the fact that AIU furnished the original COSS for this case should not influence the Commission‘s decision on this issue in any manner.

d. Commission Conclusion

By AIU's own admission, its electric COSS are not perfect. The question for the Commission is whether the COSS are too imperfect to be used in this proceeding. The Commission recognizes that it approved use of similar electric COSS in AIU's second most recent rate proceeding, Docket Nos. 06-0070 (Cons.). The fact that AIU modified the COSS since then, however, warrants fresh consideration.

Some of the alleged errors in the COSS have already been reviewed and addressed in this Order. AIU acknowledges that use of the DEMSUBTR allocator was in error and has agreed to renew use of the DDSUBTR allocator. IIEC's concerns about the class demand study employing a combination of supply and delivery voltage have been considered above as well. The Commission concluded that the class demand study should use supply voltage alone. Allocation of AIU's PURA tax liability has also already been discussed, with the Commission concluding that no change in the COSS is warranted in this respect.

One of IIEC's criticisms that has not been previously addressed pertains to the allocation of transformer rental revenue. Whether AIU acknowledges a possible error in its allocation method is not clear. AIU does, however, allege that IIEC failed to provide it an alternative to consider. The Commission understands IIEC to simply argue that transformer rental revenue from DS-4 customers should be used to offset the DS-4 class revenue requirement. IIEC seems to make the same straightforward argument for the DS-3 class. The Commission agrees with IIEC's recommendation. Under IIEC's approach, the revenues in question will be credited to the classes from which those revenues are collected. To the extent that AIU's method differs in its COSS, the Commission directs AIU to implement IIEC's straightforward approach to allocating transformer rental revenue the next time it runs its COSS.

With regard to IIEC's complaint that AIU's COSS fails to allocate costs relating to substation equipment, poles, towers, fixtures, overhead conductors and devices, and underground conduit reflected in FERC Accounts 362, 364, 365, and 366 to over 2,000 DS-3a, DS-3b, and DS-4 secondary customers, the record lacks sufficient evidence to find that IIEC is correct. If AIU has not allocated such costs to all of the appropriate customers, the Commission directs AIU to correct this deficiency the next time that it runs its COSS.

Despite having confirmed the presence of some of the errors that IIEC alleges, the Commission is not prepared to disregard AIU's electric COSS. In AIU's last rate proceeding, the Commission authorized rate adjustments on an across-the-board basis, not because of deficiencies in AIU's COSS but because the recently redesigned electric rates stemming from Docket No. 07-0165 had been in effect for less than one year. The Commission feared that returning to cost based rates so soon would lead to the same rate shock that warranted the rate redesign in Docket No. 07-0165. Since then, electricity commodity prices have dropped (for now) and the Commission generally believes that the overall impact of bills reflecting cost based delivery services will be tolerable. Therefore, the Commission finds that AIU's electric COSS, as modified in this Order, should be used in setting rates in this proceeding. IIEC may be correct regarding the other errors that it alleges exist in AIU's electric COSS, but the Commission does not consider them fatal to the COSS. AIU should therefore rerun its COSS incorporating the corrections and adjustments discussed above before finalizing rates.

The Commission notes that AIU complied with the directive in Docket 07-0585 to analyze rate alternatives for the subsidized all-electric residential customer sub-class. At this time the Commission does not direct AIU to develop an alternative rate class for all-electric customers; however, in subsequent rate proceedings, as subsidies for these customers are reduced, AIU should continue to analyze whether market based prices are competitive with marginal prices and alternative rate designs more beneficial for this sub-class of customers.

C. Contested Gas Issue - Storage Cost Allocation

AIU incurs storage costs associated with both on-system storage facilities and off-system storage facilities. On-system underground storage facility costs are recovered in base rates. Off-system underground storage facility costs are recovered only from sales customers through a different recovery mechanism and are not at issue in this proceeding. In its gas COSS, AIU allocates such on-system costs to both sales and transportation customers.[11] AIU segregates these on-system storage costs into a portion that supports the delivery function applicable to all sales customers and a portion assignable to transportation customers based on their actual peak day usage during the historic test year. Staff, on the other hand, proposes to allocate these costs based on the transportation customers' Daily Confirmed Nomination (–DCN")[12] on the same day. Nominations are the amount of gas scheduled for delivery on a pipeline to the LDC system.

1. AIU Position

Transportation customers have a limited ability to withdraw gas from their transportation banks on a peak day. AIU bases the on-system underground storage

[11] AIU provides two general categories of service to its commercial customers: they can either receive sales service (i.e., AIU sells and delivers gas to the customer) or transportation service (i.e., AIU delivers to the customer gas that the customer purchased from a third party).

[12] As defined AIU's tariffs, a DCN is the volume a transportation customer nominates and delivers to the company's delivery system for any single day. The absence of a DCN is equivalent to a DCN of zero. Such deliveries shall reflect adjustments for losses on the company's gas system. (See Ill. C. C. No. 20, 1st Revised Sheet No. 25.001)

cost allocation on the relative size of the transportation customers' withdrawal ability. On a Critical Day ("CD"), daily balanced customers can call on their storage bank for up to 20% of their DCN and monthly balanced transportation customers can call on the storage bank for up to 50% of their DCN. AIU states that it must operationally plan to serve transportation customer banks on a CD, but does not know what the transportation customers will nominate on any given day in the future. From a planning perspective, AIU assumes that transportation customers as an aggregate will call on the storage bank for 20% of their usage on a future peak day. AIU, therefore, determined the amount of on-system storage capacity planned to serve 20% of the transportation customers' peak day usage and allocated a portion of the on-system storage capacity costs based on the ratio of the transportation customers' peak day capacity usage to the total on-system storage capacity.

AIU's proposed allocation of on-system underground storage costs to transportation customers is based on the transportation customers' actual peak day usage during the 2008 test year. The following table shows the how AIU determined the allocation percentage for AmerenCIPS. In this example, AmerenCIPS' 2008 peak day usage was 60,436 therms. Excluding the usage associated with special contracts and GDS-7 customers results in 34,204 therms of relevant peak day usage. Applying AIU's actual 20% planning assumption to the 34,204 therms of relevant transportation customer peak day usage results in an expected bank withdrawal of 6,841 therms. AmerenCIPS has 38,000 therms of on system storage capacity. The 6,841 therms of expected bank withdrawal rights represents 18.00% of the 38,000 therms of on-system storage capacity available to the transportation customers.

	Calculation of the Transportation Customers' Allocation of On-System Storage Facility Costs	AmerenCIPS
(a)	Transportation customers' relevant 2008 peak day usage	34,204 therms
(b)	Planning Factor	20%
(c)	Bank Withdrawal Rights – *i.e.,* (a) times (b)	6,841 therms
(d)	Total On-System Storage Capacity	38,000 therms
(e)	Allocation Percentage – *i.e.,* (c) divided by (d)	18%

AIU therefore allocated 18% of AmerenCIPS' on-system underground storage costs to the AmerenCIPS transportation customers. The remaining 82% of the on-system storage costs was allocated to sales customers. Using the same methodology, AIU produced allocation percentages for AmerenCILCO and Ameren IP. AIU offers the following table depicting the percentage of on-system underground storage costs allocated to transportation customers under the AIU and Staff proposals. AIU and Staff disagree not only on the resulting allocation percentages, but also on the method for developing those percentages.

Proposed Allocation of On-System Storage Costs to Transportation Customers		
	AIU Allocation Based on Actual Planned Peak Day Usage (Ameren Ex. 27.3)	Staff Allocation Based on DCN (Staff Ex. 27.0 Revised at 38)
AmerenCIPS	18.00%	14.02%
AmerenCILCO	5.53%	3.96%
AmerenIP	5.21%	3.80%
Total	6.19%	4.55%

AIU, therefore, bases its proposed gas rates on the following allocations of on-system storage costs to transportation customers: (a) AmerenCIPS – 18.00%, (b) AmerenCILCO – 5.53%, and (c) AmerenIP – 5.21%. These percentages are based on the transportation customers' ability to rely on these facilities to serve their peak day usage with bank withdrawals.

Rather than allocate costs based, in essence, on the AIUs' planned deliverability to customers (i.e., the amount of capacity that AIU actually acquired and accounted for in its peak day planning for these customers), Staff recommends that AIU allocate on-system storage costs based on 20% of the transportation customers DCN on the 2008 test year peak day. The DCN for that peak day represents the amount of gas that the transportation customers intended to deliver for that peak day. Staff claims that it is more appropriate to allocate the on-system storage cost based on a percentage of DCN because AIU's tariffs allow transportation customers to call their bank capacity for up to 20% of their DCN. AIU contends that Staff's proposal is flawed.

AIU's first criticism of Staff's approach is that using only the DCN understates the cost responsibility to transportation customers with the remaining cost responsibility being absorbed by sales customers. AIU maintains that its approach of using actual peak day usage mirrors more closely a true and reasonable design day level requirement from which costs can be reasonably assigned to transportation customers. AIU's second criticism is that transportation customers' DCN is discretionary and not predictable. A transportation customer can nominate as little as zero therms for a peak day, as much as 100% of the maximum daily contract quantity ("MDCQ") for daily-balanced customers, or 200% of MDCQ for monthly balanced customers. AIU states that it is up to each transportation customer to decide how much gas to nominate on a day. The customer may not be able call on storage bank if, for example, the customer did not have a positive bank balance. Moreover, AIU adds, the customer may choose not to call on its storage bank for a commercial reason. Alternatively, AIU states that transportation customers can call on the transportation bank for as much as 20% to 40% of their MDCQ if they nominated the maximum amount available under the tariff. AIU does not know what a transportation customer individually, or transportation customers in aggregate, will nominate for any given day. Due to the discretionary nature of the DCN, AIU does not plan its resources assuming 20% of historic DCN.

AIU disagrees with Staff's contention that basing the allocation on 20% of peak day usage rather than 20% of DCN over-allocates costs to transportation customers.

While DCN levels are a fair starting or reference point, AIU maintains that the transportation customers‘ DCNs are significantly lower than the transportation customers‘ actual peak day usage. Basing the on-peak storage allocations on transportation customers‘ DCNs would materially understate the storage cost responsibility to transportation customers, according to AIU. Instead, when allocating the storage costs, AIU states that it should consider not only the starting DCN, but also the actual peak day use of transportation customers. AIU concludes that the Commission should permit it to allocate on-system storage costs based on the transportation customers‘ peak day usage that would capture the initial DCN levels, plus rather large additional levels of use.

2. Staff Position

Staff has no objections to the allocation of on-system underground storage facility costs based on the ability to withdraw gas on a peak day. Staff notes, however, that while AIU reasonably allocates these costs based on ability to withdraw gas on a peak day, it measures that ability as 20% of transportation customers‘ usage rather than the smaller amount allowed in the tariff, which is 20% of a customer‘s DCN for GDS-4 customers. DCN is the amount that the pipelines have confirmed will be delivered. Staff states that AIU treats any volume of gas that a customer uses above its DCN as a bank withdrawal. Therefore, on days where a customer expects to withdraw gas from its Rider T bank as is assumed in allocating storage cost responsibility, AIU assumes that the customer will nominates a volume of gas less than its anticipated usage. Staff asserts that AIU acknowledges that DCN will be less than usage and 20% of DCN will be less than 20% of usage. (Tr. at 856-857) According to Staff, the practical result of AIU using 20% of usage is to over-allocate storage costs to transportation customers. Consistent with AIU's tariffs that provide that transportation customers may withdraw 20% of their peak day DCN, Staff recommends that these customers be allocated the share of storage costs based on 20% of DCN rather the 20% of their peak day usage.

Staff asserts that AIU set out to allocate storage costs to transportation customers —based on the transportation customers‘ actual peak day usage during the historic test year," and —based on their ability to withdraw gas from their transportation banks on a peak day." (AIU Initial Brief at 218) Staff notes that these are not the same thing. AIU later offered a third reason: that 20% of usage (an amount in excess of tariff limits on withdrawals) represents —expected bank withdrawals" on a design day. (AIU Initial Brief at 220) Staff criticizes AIU for changing the reason behind its allocation method.

Staff understands that AIU has designed the gas distribution system for a CD. Therefore, Staff believes that it is appropriate to compare the relationship between expected usage and DCN on a CD, rather than simply on an historic peak day. AIU, however, continues to argue that bank withdrawals will be in excess of that allowed in the tariff. Staff states that AIU bases this view on the assumption that customers will under-nominate on a CD. Staff argues that under-nomination on a CD is unlikely in light of the tariff conditions that exist on CDs. For example, usage in excess of nominations and allowed bank withdrawals are subject to significant penalties of over $6 per therm.

In response to AIU's assertion that it can not predict DCN on peak days and therefore relies on usage, Staff acknowledges that it may be easier to estimate usage on peak days but contends that DCN on a CD must be close to usage. If AIU has chosen to plan its system based on bank withdrawals that are not supported by the tariff, Staff states that this should not influence cost allocation. Staff contends that transportation customers should pay based on what they can expect to withdraw on a CD. Staff relates that it is neither usage alone nor DCN alone that dictates the level of bank usage; rather, it is the difference in DCN and usage. On a CD, Staff explains that these numbers will closely track because of AIU's tariff provisions approved by the Commission to prevent one thing: the excess use of system gas that results from under-nomination.

With respect to AIU's complaint that the transportation customers' DCN is discretionary and not predictable, Staff counters that just because customers' nominations are ―discretionary" does not make them arbitrary as AIU infers. Staff maintains that AIU has not established that its transportation customers individually vary their nominations between 0 and 200% despite the allegation to that effect. Certainly this will not be the case, Staff continues, when transportation customers are considered in aggregate--which is what is what is at stake here. According to Staff, the maximum aggregate that AIU alleges individual transportation customers can nominate is not the issue here because if transportation customers nominate and deliver up to MDCQ or even 2 times MDCQ on a peak day, they would be injecting gas, not withdrawing it. Staff observes that such nominations would only cause the transportation customers' aggregate bank usage to go down.

Staff goes on to state, however, that the minimum aggregate expected nomination would be a legitimate concern. On a CD, Staff relates that transportation customers have certain ―rights" to nominate as stated by AIU; they have certain obligations as well. Realistically, Staff doubts that transportation customers would nominate that little gas. The factor limiting potential under-nomination, Staff continues, is CD penalties. All transportation customers, regardless of whether they are daily or monthly–balanced customers, face the $6-per-therm Unauthorized Gas Use Charge which could be 10 times the price of gas on that day or more. In addition, Staff reports that transportation customers would also face stringent Operational Flow Order (―OFO") balancing provisions that charge transportation customers up to 2 times the spot price for the use of system gas. Furthermore, transportation customers stand responsible for potential pipeline imbalances that they may cause. Staff argues that all of these things combine to constrain transportation customers' nominations to a reasonable level. AIU's assertion of wildly vacillating nominations between 0 and 200% of MDCQ is simply not realistic, according to Staff, in light of AIU's exiting tariff terms. Staff maintains that AIU focuses on serving the bank withdrawals of transportation customers and ignores the other side of the tariff that is designed to protect the system on a CD.

AIU also indicates that some customers may not be able to withdraw gas on the CD because they may lack sufficient capacity in those banks. These customers, AIU states, will have to nominate below their usage to reduce the risk of Unauthorized Gas Use Charges, which would reduce the aggregate bank withdrawal below the 20% amount. Staff observes that another reason listed by AIU is that customers may choose to not use banks for commercial reasons. Staff states that this would once again mean that they would have to nominate more than they would otherwise and would also reduce the aggregate bank withdrawal. According to Staff, these examples of discretionary behavior actually point to a lower expected bank withdrawal. Staff contends that AIU can not point to a singe reason why transportation customers would reduce nominations on a CD and completely ignores the CD penalties which may be 10 times the market price or more.

Therefore, Staff continues to recommend that these customers be allocated the share of storage costs based on tariff rights that provide withdrawals of 20% of DCN rather the 20% of their peak day usage. Using 20% of DCN changes the storage allocator in Ameren Ex. 27.3 from 18.00% for AmerenCIPS to 14.02%, from 5.53% for AmerenCILCO to 3.96% and from 5.21% for AmerenIP to 3.80%.

3. Commission Conclusion

Generally, the Commission approves of allocating on on-system underground storage costs based on the relative size of the transportation customers' withdrawal ability on a peak day. While AIU bases the allocation on 20% of transportation customers' aggregate usage on the 2008 peak day, Staff recommends basing the allocation on 20% of transportation customers' aggregate DCN on the 2008 peak day. There is no dispute that 20% of usage is a greater number than 20% of DCN on the peak day. Nor is there a dispute that AIU's method allocates more on-system storage costs to transportation customers that Staffs' method. The question is which method is more representative of costs transportation customers impose on the storage system.

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.

IX. RATE DESIGN/TARIFF TERMS AND CONDITIONS

The above discussion on how to allocate costs among the classes of electric and gas customers is but one component of rate design. Rate design, in the parlance of the Commission, also encompasses the terms and conditions of service in a utility's tariffs. Over the course of this proceeding, parties raised several issues and presented arguments concerning the terms and conditions of service. Some of these issues have been resolved, while others remain contested.

A. Resolved Gas and Electric Issues

1. Uncollectibles Factors

Pursuant to Section 2 of the stipulation in Docket No. 09-0399, AIU and Staff have agreed to the following regarding the determination of uncollectibles factors concerning Rider EUA and Rider GUA:

> . . . the uncollectible amounts included in rates for the periods on and after the date new rates take effect (pursuant to 09-0306 et al (Cons.)) shall be determined for each relevant customer rate class as defined in Rider EUA as follows:
>
> a. For [delivery service ("DS")], the uncollectible amounts included in rates shall be the amount equal to the DS uncollectible component as stated in the compliance DS tariff sheets as a dollar amount per customer, per month multiplied by the number of customers. The DS uncollectible component would be included within the stated DS monthly customer charge and not appear on customer bills as a separate line item. The AIU will provide Surrebuttal Testimony on this item in the pending rate case.

The parties agreed in Docket No. 09-0399 to a similar provision with respect to Rider GUA. AIU proposes that the ―average amount per customer per month" be listed in the appropriate DS tariff in the Terms and Conditions section. These amounts will be tracked within AIU's billing system and serve as the base amount of uncollectibles included in rates, required for use in conjunction with Riders EUA and GUA. AIU's calculations will be updated to conform to the expense level authorized by the Commission at the conclusion of the rate case. AIU and Staff are in agreement on this issue. The Commission finds the resolution of this issue appropriate and consistent with its decision in Docket No. 09-0399.

2. Miscellaneous Tariff Language Changes

With regard to the Terms and Conditions of Service section of AIU's gas and electric tariffs, Staff and AIU are in agreement on various modifications. Language revisions that AIU proposes include wording modifications and date changes in the electric —Switching Suppliers" subsection and language changes in the electric —Disconnection and Reconnection" subsection. Staff is agreeable to AIU's proposed $400 fee for customers whose service has been disconnected at the main because access to the meter was blocked. Staff also supports AIU's proposal to eliminate the references to GDS-6 in AmerenCILCO's gas tariffs if the Commission approves the elimination of GDS-6 for AmerenCILCO.

Concerning AIU's Standards and Qualifications for Electric Service, AIU and Staff are in agreement on AIU's proposed language changes to paragraph 4(B), which imposes a $170 fee per meter read. Effectively, this section was amended to include a provision to require non-residential customers to provide a means for remote meter interrogation or to require a $170 meter reading fee when AIU's personnel do not have free access to the meter. Staff also recommends approval of AIU's proposed word additions/deletions and page updates in the Index subsection of the tariffs, AIU's proposed elimination of certain sentences and phrases in the Service Extension paragraph including ones exclusive to Ameren IP, AIU's proposed language additions and deletions to the Interval Metering subsection paragraph, and AIU's proposed language revisions in section C of Standards and Qualifications for Gas Service.

Regarding the DS-2, DS-3, and DS-4 tariffs, AIU proposes language changes to 4th Revised Sheet No.12.002 where the wording was changed to clarify that AIU's personnel could install unmetered services without first receiving a request from customers to do so. In 7th Revised Sheet No. 13, 6th Revised Sheet No. 13.001, 6th Revised Sheet No. 13.002, 7th Revised Sheet No.14, and 6th Revised Sheet No. 14.001, AIU proposes minor language and sentence changes to the last two paragraphs. Staff recommends approval of the proposed language changes because it improves clarity across AIU's tariffs without changing the substance of the current tariff language.

In the context of Rate DS-5, since some light fixtures are no longer available, AIU proposes language modifications to 4th Revised Sheet No.12.002. Staff accepts AIU's proposed modifications.

With regard to the Miscellaneous Fees and Charges Section of its tariffs, AIU proposes changes in 2nd Revised Sheet No. 35.001. Staff agrees that the proposed changes add clarity and helpful directional information. Staff also accepts the establishment of a $170 non-scheduled meter read for customers in the GDS-4 and GDS-7 rate classes.

The Commission finds all of the miscellaneous changes described in this subsection reasonable and accepts them for inclusion in AIU's tariffs.

B. Resolved Gas Issues

1. Rate Capping Mechanism

AIU's current gas rates generate different rates of return for each rate class. One of AIU's rate design goals in these proceedings is to move each of the utilities' rate classes closer to its revenue requirement by assuming an equalized revenue requirement for each rate class within each utility. An equalized class revenue requirement would be those revenue levels required for each rate class if they were to eliminate all inter-class subsidization and produce exactly the same ROR as the overall level for each utility.

AIU, however, determined that adopting an equalized ROR level for each rate class would result in rate increases that in many instances would be so great as to result in rate shock. AIU, therefore, proposes to limit the rate increase for each rate class to a specified percentage over present rates to avoid these adverse bill impacts. If a class rate increase is limited by the rate capping mechanism, then the amount of that rate class' revenue requirement that is above the cap would be recovered from the rate classes that have not reached the cap. AIU proposes a 20% cap for AmerenIP customers and a 30% cap for AmerenCILCO and AmerenCIPS customers. The higher increase for AmerenCILCO and AmerenCIPS addresses a much larger difference in ROR and revenue deficiency levels for certain rate classes.

Staff agrees with AIU's proposed gas rate capping mechanism and recommends that the Commission approve it. Staff believes that AIU considered bill impacts and notes that while some inter-class subsidies will be necessary, those subsidies will lessen the impact of the rate increase for many AIU customers. According to Staff, AIU's proposed rate capping mechanism mitigates the concerns associated with adopting the full cost of service results and the prospect of unfavorable rate impacts that could otherwise result for some rate classes, especially due to the reclassification of rate class definitions for AmerenCILCO and AmerenCIPS. Staff also observes that the rate capping mechanism levels the distribution of the increase and spreads the proposed interclass subsidy over all other rate classes.

No other party commented on AIU's proposal. The Commission finds AIU's proposed rate capping mechanism reasonable and approves it. However, the Commission generally supports rates designed to reflect the cost of service, and is committed to eliminating these subsidies at the earliest opportunity. 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.

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

AIU proposes a gas rate design using the cost of service based on each of the utility's revenue requirements. Once revenue targets were established for each of the rate classes, AIU relates that the rate design process was guided by three general principles moving rates towards reasonable customer impacts: (1) considering the rate capping mechanism described above; (2) eliminating inconsistencies between the three utilities' rate designs; and (3) emphasizing the 80%/20% fixed/variable thresholds authorized by the Commission for GDS-1 and GDS-2 rates in AIU‘s last rate cases.

Staff agrees with and recommends approval of AIU‘s overall proposed rate design. Staff believes that AIU properly considered bill impacts and the Commission‘s directives from the last rate order. To account for the difference between AIU's revenue requirement and Staff's revenue requirement, Staff proposes to scale AIU‘s proposed rates by the ratio of Staff's revenue requirement for each utility. This method does not alter AIU's general rate design. Instead, it simply increases or decreases the rates in proportion to the change in the revenue requirement.

In the event the Commission determines a different revenue requirement, AIU and Staff agree that use of Staff's scaling method is appropriate. No other party addressed this issue. The Commission finds AIU's overall rate design reasonable and directs that Staff's scaling proposal be used to reconcile the approved revenue requirement with the adopted rate design.

3. Interval Meter Data Access Fees

AIU no longer needs real-time data connections to its GDS-2 and GDS-3 customer meters. Because many of these customers have expressed a desire to maintain access to daily usage information, AIU proposes an optional Daily Usage Information Service with a data access fee that would reflect the cost of modifying the existing metering to make it capable of transmitting the daily meter information to AIU. AIU estimates that the installation of a modem and associated equipment necessary to provide this optional service would result in an upfront, one-time charge of either $1,944 (if an Electronic Pressure Corrector – Pulse Accumulator is required) or $812.25 (if no Electronic Pressure Corrector – Pulse Accumulator is required). AIU proposes a $5.00 monthly service charge for this optional service. AIU proposes and Staff accepts the following new tariff language to implement the updated installation charge:

> If Customer elects such service, the Company may be required to install a remote monitoring device to provide daily usage information to Customer. If Company is required to install a remote monitoring device in order for Customer to receive Daily Usage Information Service, Customer will be required to pay Company for the cost of equipment and installation, prior to receiving service, as follows.
>
> $1944.00, for each meter where installation of a pulse accumulator is required.
>
> $812.25 for each meter where installation of only a modem is required.

GFA also approves of this provision and states that it supports making the service available as an option at a fee that recovers actual costs. No other party addressed this issue. The Commission finds the proposal reasonable and approves its inclusion in AIU's tariffs.

4. Calculation of "Highest Average Daily Use"

AIU proposes to determine the eligibility for a number of rate classes based on the customers "highest average daily usage" ("HADU"). AIU proposes to determine the HADU by dividing the customer‘s total usage in a billing period by the number of days in that billing period. GFA agrees with this method. No other party commented on the calculation method. The Commission accepts the proposed method for calculating a customer‘s HADU for determining a customer‘s rate eligibility.

5. Rider T - Gas Transportation Service

a. NAESB Intraday Nomination Cycles

The North American Energy Standards Board (―NAESB") is a non-profit industry forum created to develop uniform business practices intended to create a seamless marketplace for wholesale and retail natural gas and electricity. NAESB has developed gas industry standards on many matters for improved functionality in the gas industry between pipelines, LDCs, third party suppliers, and other industry participants. Among the standards developed by the NAESB is one which calls for four nomination cycles. A "nomination" is how transportation customers schedule gas deliveries from a pipeline onto a LDC's system.

AIU initially proposed to retain its existing two nomination deadlines for transportation customers. Currently, AIU permits transportation customers to submit nominations at 11:30 a.m. and 4:00 p.m. to identify the gas to be delivered on the next gas day. Staff and CNE-Gas, on the other hand, proposed that AIU permit transportation customers to submit nominations based on NAESB's Intraday 1 and Intraday 2 nomination schedules. After discussing the issue amongst themselves, AIU, Staff, and CNE-Gas now agree that new tariff language implementing a single ―same day" nomination schedule at 7:30 a.m. (rather than the NAESB Intraday 1 and Intraday 2 schedules) is a reasonable solution. The parties agree that the same day nomination reasonably balances AIU‘s interest in maintaining system reliability with the customers‘ interest in additional flexibility. AIU‘s tariffs require the utilities to use their best efforts to accommodate any other off-cycle nominations. AIU, however, currently does not provide transportation customers with the firm right to submit intraday nomination changes. The new tariff language implementing a new ―Same-Day" nomination as part of the Nomination of Customer-Owned Gas section of each of the Rider-T tariffs reads as follows:

> Same-Day
> Customer desiring a change in Nomination for transportation of Customer-Owned Gas after the Intra-Day deadline specified above shall notify Company by 7:30 A.M. CST of the business day on which the Nomination is to take effect, subject to confirmation by the pipeline. Company may accept such change to Customer's Nomination if the Company determines in its sole discretion that such a change to Nomination will not adversely impact the operation of the Company's gas system or adversely impact Company's purchase and receipt of gas for other Rates or Riders.

No other party addressed the issue of nomination deadlines. The Commission finds the resolution of this issue and the new tariff language reasonable and approves of the inclusion of the language in AIU's tariffs.

b. Notice for Operational Flow Orders and Critical Days

When a gas utility needs to curtail gas to customers, it may declare an OFO or CD. AIU initially proposed to retain the existing tariff language regarding prior notice of OFOs and CDs. Staff proposed that AIU make a good faith effort to give a 24-hour notice of OFOs or CDs. CNE-Gas proposed that AIU provide notice as far in advance as possible--normally not less than two hours, unless conditions warrant immediate implementation of the OFO or CD. In response to the concerns expressed by Staff and CNE-Gas, AIU agrees to provide advance notice of an OFO or CD as far in advance as reasonably possible. Moreover, AIU agrees to submit a report to the Commission (specifically, the Director of the Energy Division) within two business days if it does not provide a 24-hour notice. In particular, AIU states that it is willing adopt the following tariff language as part of the Rider T section titled System Integrity Protection:

> The Company shall provide notice of a Critical Day and OFO as far in advance as reasonably possible, normally not less than two hours, unless the Company believes conditions warrant immediate implementation of the Critical Day or OFO. If the Company issues a Critical Day or OFO notice within 24 hours of the Critical Day or OFO taking effect, the Company will report to the Commission indicating why customer notice of less than 24 hours was necessary.

Staff and CNE-Gas support adoption of the proposed addition to Rider T. The Commission finds the proposed language reasonable and approves of the inclusion of the language in AIU's tariffs.

6. Large Customer Rate within GDS-4 Rate Class

Of the three gas utilities, only AmerenCILCO currently has a rate class for customers with annual usage in excess of 2,000,000 therms--the GDS-6 rate class. AmerenCIPS and AmerenIP customers with usage in excess of 2,000,000 therms are covered under the GDS-4 rate class. AIU proposes to eliminate AmerenCILCO's GDS-

6 rate class as a stand-alone tariff and transfer the GDS-6 customers to AmerenCILCO's GDS-4 rate class. AIU then proposes to modify only AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. Because neither AmerenCIPS nor AmerenIP have a GDS-6 rate class, AIU states that introducing large customer provisions to the AmerenCIPS and AmerenIP GDS-4 tariffs is unwarranted and would introduce an unnecessary level of complexity. AIU proposes to include a price step in AmerenCILCO's GDS-4 tariff simply to promote stability for the existing customers served under AmerenCILCO's GDS-6 tariff. AIU states further that AmerenCILCO's special provisions for large customers are one of the few instances where other factors take precedence over the desire for tariff uniformity.

AIU agrees with Staff's recommendation that, in the time between these rate cases and the next rate cases, AIU should assemble data associated with AmerenCIPS' and AmerenIP's GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. While AIU is only proposing these tariff provisions for AmerenCILCO in these rate cases, AIU agrees that assembling this data may help provide support to AIU's gas tariff design in the next rate case.

Staff recommends approval of (1) AIU's proposal to eliminate AmerenCILCO's GDS-6 tariff as a stand-alone rate class and (2) the special large customer provisions under AmerenCILCO's GDS-4 rates. Staff does not seek the immediate adoption of identical terms for larger AmerenCIPS and AmerenIP GDS-4 customers because it recognizes that AIU has not assembled the necessary data to implement this change. By its next rate case, Staff believes that AIU should have evaluated the relevant data to determine whether a similar rate design is appropriate for large customers of AmerenCIPS and AmerenIP with usage of more than 2,000,000 therms annually.

The Commission understands no other party voiced a position on this matter and that AIU and Staff are in agreement. The Commission finds AIU's proposal to eliminate AmerenCILCO's GDS-6 tariff reasonable, as well as its proposal to modify AmerenCILCO's GDS-4 tariff to mitigate any adverse rate impact for former GDS-6 customers. The Commission also considers it appropriate for AIU to assemble data associated with AmerenCIPS' and AmerenIP's GDS-4 customers with annual consumption over 2,000,000 therms to evaluate whether AmerenIP and AmerenCIPS should implement special GDS-4 rate provisions for those customers. The Commission expects the results of such efforts to be presented in AIU's next rate case.

C. Resolved Electric Issues

1. Rider PER - Purchased Electricity Recovery

AIU proposes to modify Rider PER - Purchased Electricity Recovery ("Rider PER") so that it identifies this docket as establishing Basic Generation Service ("BGS") base prices, replacing a reference to the rate redesign case, Docket No. 07-0165. AIU states that this change is necessary to the extent the Commission accepts AIU's proposal to adjust BGS-1 and BGS-2 prices in this proceeding. In response, Staff suggests one minor change to Sheet No. 31.008, which AIU accepts. The Commission finds the agreed to language reasonable and adopts it.

2. Supply Cost Adjustments for Rider PER

A Supply Cost Adjustment ("SCA") is applied to customers billed under Rider PER for recovery of certain costs for procurement (Supply Procurement Adjustment), working capital (CWC Adjustment), and uncollectibles (Uncollectibles Adjustment). AIU describes a detailed plan for recovering the costs related to its power supply through the SCA. In response, Staff proposed one change to the Supply Procurement Adjustment and two changes to the Uncollectibles Adjustment. Those changes are: (1) a corrected amount for costs associated with the procurement of power; (2) the uncollectibles factors for recovery under Rider PER should be consistent with the uncollectibles to be recovered through base rates; and (3) the allocation of write-offs between gas and electric service for combination customers should be based on the relative revenues for each type of service. AIU agrees with Staff‘s recommendation that $1,278,100 should be approved as the Supply Procurement Adjustment component of Rider PER. Staff also accepts AIU‘s counter proposal for the uncollectibles percentages based on net write-offs as a percentage of revenues, using calendar years 2007 and 2008 and year-to-date September 2009. Staff is no longer advocating its third recommendation. AIU and Staff are now in agreement on these revisions. The Commission finds the proposal reasonable and adopts it.

3. Rider RDC - Reserve Distribution Capacity

AIU proposes a change to Rider RDC - Reserve Distribution Capacity to ensure that the phrases —Demand” and —Bihg Demand” are not interchangeable terms. Presently, —Demand” and —Bihg Demand” share the same definition, but the term —Bihg Demand” is adjusted within both the DS-3 and DS-4 tariffs to carry a different meaning. In response, Staff suggests that the term —bihg demand” not be capitalized. AIU has agreed to this revision. The Commission finds the revisions reasonable and adopts it.

4. Rider QF - Qualifying Facility

AIU proposes to eliminate a provision in Rider QF - Qualifying Facility ("Rider QF") that allows it to refuse to accept output from a qualifying facility when the purchase of the output does not permit it to avoid costs. AIU currently uses energy purchases to offset power procured on behalf of fixed-price customers. Qualifying facility purchases usually influence the quantity of energy AIU buys and sells through the MISO-administered markets as AIU balances its fixed price energy portfolio. As long as there is a MISO-administered market, AIU does not anticipate a situation where the purchase of output from a customer‘s qualifying facility would permit AIU to avoid costs. As such, AIU proposes to eliminate this section. No party opposes this revision. The Commission finds the proposed change reasonable and approves it.

5. Rider HMAC - Hazardous Materials Adjustment Clause

Costs related to hazardous materials claims are recovered under AIU's Rider HMAC - Hazardous Materials Adjustment Clause ("Rider HMAC"). The HMAC BASE Amount, as defined in Rider HMAC, is the amount of HMAC costs reflected in the test year in the most recent electric rate case Commission order. This amount is needed to determine the amount to be withdrawn or deposited annually into the HMAC Cost Fund. Staff observes that the BASE Amount included in AmerenIP's revenue requirement is $411,889 and requests that the final order in this proceeding clearly indicate this BASE Amount for ease in applying Rider HMAC in future periods. AIU agrees that the HMAC BASE Amount included in AmerenIP's revenue requirement is $411,899. The Commission concurs.

6. DS-4 Reactive Demand Charge

Staff recommends that AIU modify language in the Standards and Qualifications for Electric Service section of each utility's tariffs. Staff believes that the existing language could give the false impression to Rate DS-4 customers that they can avoid monthly reactive demand charges if they maintain a power factor within the range 95% lagging to 95% leading. In actuality, based upon AIU's Rate DS-4 tariff, Rate DS-4 customers with a supply voltage below 100 kV can not, in practical terms, avoid a monthly reactive demand charge. In response to Staff's concerns, AIU proposes to add an additional sentence to this section of its tariffs that better explains reactive demand charges for Rate DS-4 customers. Staff finds AIU's proposed language adequate. The Commission finds the modification reasonable and approves its inclusion in AIU's tariffs.

7. Tail Block Variable Charges

While AIU initially proposed a 10% increase in the total variable charges for tail block BGS-1 and BGS-2 rates, it now agrees with Staff and urges the Commission to approve an increase to the total variable charges for tail block BGS-1 rates of 13%. AIU and Staff continue to support a 10% increase in the total variable charges for tail block BGS-2 rates. As Staff noted in its Initial Brief, without this increase in the BGS-1 rates, AIU incurs a shortfall of approximately 4 cents for each kWh sold to AmerenCIPS-ME and AmerenIP space heating customers, as well as a deficit of between 2 and 3 cents for each kWh sold to AmerenCIPS space heating customers. AIU adds that this increased charge unburdens the remaining bundled customers who would otherwise have to make up for this shortfall. AIU states that this increase is necessary to assist in reducing the amount of subsidy inherent in the present BGS-1 rates for non-summer use over 800 kWh.

Staff and AIU also agree that the annual cost effect of increasing the tail block variable charge by 13% for DS/BGS-1 customers would be minimal. The incremental increase for customers using 18,000 kWh per year would be about $1.50 at AmerenIP, $3.50 at AmerenCIPS, $1.00 at AmerenCIPS-ME, and $4.50 at AmerenCILCO.

Similarly, a space-heat customer using 26,000 kWh per year would experience annual increases of about $7.00 at AmerenIP, $10.00 at AmerenCIPS, $5.30 at AmerenCIPS-ME, and $11.75 at AmerenCILCO.

The Commission concurs with AIU and Staff that the tail block variable charge for DS/BGS-1 customers should increase by 13%. The customer impacts of this change are minimal. Raising the tail block rate is also a step in the right direction toward eliminating a subsidy. The Commission also finds the proposal to raise the tail block rate for DS/BGS-2 customers by 10% reasonable. The AIU and Staff agreement on the issue of tail block rates for BGS-1 and BGS-2 rates is adopted.

8. Cost Based Seasonal Rate

In support of its argument for seasonal distribution rates, GFA states that transformers for DS-3 and DS-4 customers are often sized to serve only one customer, for which costs are recovered via a Transformation Charge specific to that customer. Similarly, meters and service are specific to one customer and these costs are recovered in the Customer Charge and Meter charges. As AIU confirms in response to data request PL4.02, however, GFA asserts that the rest of the electric distribution line and substation system capacities are built to carry the aggregate peak coincidental load of all customers served from each part of the system. GFA understands that summer month coincident peaks are typically higher on the AIU system than are winter month coincident peaks. Because the coincidental system peaks on the AIU system vary by season, GFA concludes that AIU's distribution system cost of service varies by season. Therefore, GFA maintains that AIU should price its distribution delivery service charges, excluding monthly fixed charges, higher during the summer and lower during the non-summer months. As in AIU's last rate case, GFA simply requests that AIU begin collecting the necessary data to conduct analysis of prospective seasonally cost based rates for the DS-2, DS-3, and DS-4 classes with regard to costs of substations and primary lines within the Distribution Delivery Charge.

AIU does not believe that implementation of a seasonal Distribution Delivery Charge is as simple as GFA suggests. GFA reasons that since as a group, the non-residential classes tend to peak in the summer, additional costs, and thus, greater rates, should be assigned to the summer period. AIU points out, however, that substations and primary lines are designed to serve the maximum demand expected on the facilities, regardless of the season. AIU adds that circuits serving customers with large grain drying loads can, and do, peak in the fall season. To provide this subclass with a lower rate in the non-summer season, AIU continues, would send an incorrect price signal to these customers. Instead, AIU asserts that a cost-based seasonal rate for this subclass would likely have greater demand charges in the fall, which would encourage customers to be as efficient as possible in managing their peak demands, since it is their demands that contribute the most to the need for substation and primary line capacity.

Additionally, because the DS-2 class already contains a seasonally-differentiated price, and the non-summer delivery charge is lower than the summer charge, AIU contends that seasonal pricing is unnecessary with respect to that class. AIU goes on to state that one can not consider seasonal rates without examining the price incentives and the possible cost consequences those price signals would have on distribution system costs. AIU suggests that a lower non-summer rate for certain customers (here, grain dryers) would signal that delivery service to them is cheaper, providing customers an incentive to use more, even though the delivery system with large grain drying load may already be constrained at the time of the fall peak.

AIU states further that DS-4 and large DS-3 customers connected at the primary voltage supply level can be large enough to drive local circuit peaks. AIU also indicates that examining seasonal rates for non-residential customers requires attention to circuit level details rather than aggregate demands of all customers -- a highly manual process. Nevertheless, AIU acknowledges that examining a sample of circuits serving DS-3 and DS-4 customers may help bring additional clarity to the debate. The study would also measure such customers' revenue contribution relative to their cost responsibility -- the issue GFA wishes AIU to examine. AIU is interested in proper cost allocation and pricing, and thus does not object to further study in the next rate case.

The Commission understands that GFA and AIU are in agreement that this issue will be addressed in AIU's next electric rate proceeding. The Commission also understands that prior to that time AIU will study a sample of circuits serving DS-3 and DS-4 customers to evaluate such customers' revenue contribution relative to their cost responsibility. The Commission believes that doing so is reasonable and directs AIU to conduct the described study and provide the results with its next electric rate case filing.

D. Contested Gas Issues

1. Availability Tariff Provisions

a. AIU Position

Pursuant to the Commission's direction in its last rate cases, AIU proposes a number of changes to its tariffs in these rate cases with the goal of achieving uniformity in tariff provisions. AmerenCILCO, AmerenCIPS, and AmerenIP all have similar non-residential rate classes GDS-2, GDS-3, and GDS-4. The availability (or eligibility) provisions of those rate classes, however, differ from company to company. In considering an appropriate availability threshold, AIU sought to use the existing availability provisions and/or methodologies of one of its companies. The AmerenIP tariff currently assigns customers to rate classes GDS-2, GDS-3, and GDS-4 based on each customer's actual HADU. AIU observes that the AmerenIP availability provisions provide customers with an immediate and definitive classification method using easily accessible information. On the other hand, the current AmerenCILCO and AmerenCIPS availability criterion rely upon methods of meter size, calculation of connected gas load, and definition of ―general" use. Because AIU believes that usage-based availability provisions are the easiest for customers to understand and its staff to administer, AIU proposes moving AmerenCILCO and AmerenCIPS to the AmerenIP availability methodology.

AIU analyzed the major cost differences in the meters that are currently used to serve the various customer groups in order to determine whether the usage thresholds should be adjusted from the current AmerenIP levels. AIU reports that the analysis indicated that the existing AmerenIP usage thresholds follow the major cost differences in the meters. AIU conducted the COSS and individual customer impact studies on customers of all three utilities using the HADU thresholds proposed in its tariffs. The result of this change for most gas customers will be some migration from GDS-4 to GDS-3 or from GDS-3 to GDS-2. AIU states that customers moving down a rate class as a result of this change should not face detrimental bill impacts.

AIU notes that GFA supports its goal of achieving uniformity of in its tariff provisions. But GFA objects to two elements of AIU's availability proposal. First, GFA argues that a customer's HADU should be based only on the customer's usage in the months of December through March. Second, GFA argues that the cutoff between GDS-3 and GDS-4 should be based on the annual usage criteria currently employed at AmerenCILCO rather than HADU. The following table summarizes the key differences between AIU's proposal and GFA's proposal:

	AIU's Proposed Availability Provision	GFA's Proposed Availability Provision
GDS-2	<u>Upper Limit</u>: HADU < 200 therms	<u>Upper Limit</u>: HADU < 200 therms – measured only in the billing months of December through March
GDS-3	<u>Lower Limit</u>: HADU ≥ 200 therms <u>Upper Limit</u>: HADU < 1000 therms	<u>Lower limit</u>: HADU ≥ 200 therms – measured only in the billing months of December through March <u>Upper Limit</u>: annual usage of 250,000 therms. <u>Alt. Upper Limit</u>: HADU < 1000 therms – measured only in the billing months of December through March
GDS-4	<u>Lower Limit</u>: HADU ≥ 1000 therms	<u>Lower Limit</u>: annual usage of 250,000 therms. <u>Alt. Lower Limit</u>: HADU ≥ 1000 therms – measured only in the billing months of December through March

With regard to GFA's first complaint, AIU understands why GFA would pursue rate structures that are advantageous to its membership – a group whose primary gas usage typically occurs outside the months of December through March. AIU understands that a typical grain drier will use about 80% of its annual natural gas volume during harvest, which is about a two month period in the fall. AIU suggests that the intent of GFA's proposal is to address the seasonal usage of its membership. But according to AIU, its tariffs already recognize the different impacts that seasonal customers have on fixed and variable costs, and reflect that recognition in the billing components and associated charges in the GDS-5 rate class. The GDS-5 rate class enables customers who use gas only on days when the average temperature is forecasted to be above 25 degrees Fahrenheit to avoid paying a demand charge. Since the December through March timeframe is the time of year when it is most likely that the temperature will be 25 or lower, AIU asserts that the GDS-5 rate accomplishes GFA's goal. AIU maintains that using GFA's proposed four-month calculation period to determine rate availability would simply result in an inequitable assignment of fixed costs. Moreover, AIU states that adding a seasonality component to the other gas delivery service tariffs is unsupported, redundant, and inconsistent with the goal of uniformity.

AIU strongly disagrees with GFA's contention that there is little difference between its proposal and AIU's proposed availability criterion. By grossly understating the impact that its proposal will have on customers, AIU argues that GFA fails to recognize that its proposed modification is likely to lead to an inequitable assignment of costs among customer classes. In fact, AIU continues, under the GFA proposal, it is very likely that many of the seasonal customers would move to a lower tariff class than would be justified, based on the investment and equipment needed to serve their loads. AIU insists that GFA's position for restricting HADU measurement to the December through March timeframe ignores that the bulk of the costs to build, operate, and maintain gas delivery systems are fixed charges which do not vary based on the time of year that the usage occurs, and that all users of the system should pay an equitable share of those costs. According to AIU, GFA's proposal would result in customers using the system during non-peak periods paying nothing towards the fixed costs of operating the system. AIU asserts that the Commission previously recognized the need for all users of the system to pay their share of the fixed costs, regardless of the amount of gas they use or the time of year when the usage occurs, by placing 80% of fixed cost recovery into the Customer Charge for GDS-1 and GDS-2 customers.

Furthermore, AIU maintains that GFA's proposal is unworkable because customers could simultaneously qualify for the GDS-2 and GDS-3 or GDS-4 rate classes. As an example, AIU states that if a grain-drying customer had an average daily use of 1,500 therms during the September through November harvest season, and minimal usage for the rest of the year, under GFA's proposal, the customer's annual usage could exceed 250,000 therms and result in the customer being assigned to GDS-4. The customer would then be required to implement daily balancing and install a phone line, and AIU would need to install interval metering to record this usage appropriately. The same customer, however, plausibly would have a HADU of less than 200 therms per day during the non-harvest December through March timeframe, which would result in the customer being assigned to GDS-2 and able to balance monthly, with no need for a phone line or extensive metering. AIU does not mean to suggest that the customer would change between rates more than once a year. AIU simply means that the GDS-2, GDS-3, and GDS-4 rates are not intended to be a menu of options from which customers can choose once each year. AIU states that this would not only cause confusion for customers, but also add ambiguity for rate administration, which would result in financial uncertainty for the recovery of a utility‘s approved revenue requirements. AIU adds that tariff applicability provisions that allow a customer to select between standard GDS rate classes without any meaningful change in usage patterns can also be detrimental to other customers over the long run, as rates are established in future rate cases.

Despite proposing entirely new availability provisions for all three of the companies, AIU points out that GFA does not provide any rate design, cost allocation, or bill impact analysis. AIU contends that GFA simply desires a change that it thinks will benefit its membership without any consideration of the potential impact on other customers. In contrast, AIU asserts that it has prepared and presented a unified, consistent rate design plan supported by the appropriate analysis and consideration. AIU also contends that GFA simply rehashes arguments from the last AIU rate cases, which the Commission rejected.

Regarding GFA's second complaint concerning the cutoff for service under the GDS-3 and GDS-4 rate classes, AIU asserts that GFA provides no analysis supporting its proposal to use a maximum annual usage of 250,000 therms as the cutoff. Instead, AIU notes that GFA supports its availability proposal only with the claim that the 250,000-therm maximum annual usage limit is based on the existing lower limit of AmerenCILCO‘s GDS-4 rate class. AIU contends that GFA does not explain why it prefers the AmerenCILCO cutoff to the AmerenIP cutoff. To determine availability for GDS-3 using the GFA methodology, AIU would use both a daily average calculation based on a four-month window (to determine the lower limit), as well as a total usage threshold that considers 12 months of usage (to determine the higher limit). In contrast, AIU states that its proposal is easier for customers to understand, and for AIU to administer, because it relies only on a single calculation of the customer‘s HADU to determine both the upper and lower limits. AIU finds it notable that GFA supports using a 1,000-therm HADU cutoff (measured from December through March) between GDS-3 and GDS-4 as an alternative.

b. GFA Position

GFA supports consistent eligibility requirements and tariff structures among the three companies. GFA, however, questions whether AIU has chosen the most appropriate eligibility requirements from among all AIU current rates. While GFA agrees with using a 200 therm or less HADU eligibility requirement for the GDS-2 rate class, GFA recommends that the HADU be tested only for usage during the billing months of

December through March, when system daily maximum usage is greatest. GFA denies that its proposal would result in customers potentially simultaneously qualifying for the GDS-2 and GDS-3 or GDS-4 rate classes, because of differing monthly usage throughout the year. GFA, like AIU, proposes only one annual eligibility test and supports the proposed AIU tariff provision which specifically prohibits customers from switching between rates throughout the year. The GDS-2, GDS-3, and GDS-4 tariffs each contain similar language to prevent switching under the heading Delivery Service Rate Reassignment. The GDS-2 tariff states, "[o]nce the Customer has been assigned to Rate GDS-3 or GDS-4, the Customer will not be eligible to receive service under Rate GDS-2 for a minimum of 12 monthly billing periods following such reassignment." The GDS-3 and GDS-4 tariffs have comparable language. GFA concludes that its proposal would therefore give customers a choice only once annually, but each choice carries a year long commitment.

Regarding the next rate class, GFA observes that both its and AIU's GDS-3 recommendations match up low-end GDS-3 eligibility to the high-end eligibility for GDS-2 (with the exception of GFA's December through March measurement period). GFA's high-end cutoff for the GDS-3 rate class, however, differs. GFA notes that the current AmerenCILCO and AmerenCIPS GDS-3 rates have no maximum to qualify for the rate. The current AmerenCIPS GDS-4 rate has no minimum use requirement and the current AmerenCILCO GDS-4 has a minimum annual use requirement of 250,000 therms. To be more consistent with current eligibility requirements of all three companies' GDS-3 and GDS-4 rates, and to have the high-end requirement for GDS-3 match up with the current low-end requirement of AmerenCILCO‘s GDS-4 rate, GFA recommends matching all three companies‘ GDS-3 high-end eligibility to AmerenCILCO‘s simple and straightforward current minimum GDS-4 requirement of a maximum annual use of 250,000 therms. Alternatively, GFA recommends AmerenIP‘s current GDS-3 requirement of HADU equal to or greater than 200 therms per day and less than 1,000 therms per day, except that the annual eligibility test be made on customer usage only for the peak system usage billing months of December through March.

GFA disputes the appropriateness of the cutoff between the GDS-3 and GDS-4 rate classes as well. Despite AIU's claim that it analyzed appropriate cutoff points, GFA in essence suggests that AIU arbitrarily chose to apply the AmerenIP cutoff points. Contrary to AIU's use of the AmerenIP cutoff points, GFA recommends an annual minimum use of 250,000 therms to be the eligibility threshold for the GDS-4 rate schedule for all three companies. Alternatively, GFA recommends AmerenIP‘s current GDS-4 requirement of HADU equal to or greater than 1,000 therms per day, except with the annual eligibility test being applicable to customer usage only for the billing months of December through March. GFA believes that its proposal would promote system reliability by discouraging system utilization during peak or near peak load periods, and greater system utilization during non-peak periods.

GFA denies that its proposal would result in some customers using the gas distribution system during off-peak periods paying nothing towards the fixed costs of operating the system. GFA suggests that AIU could establish a minimum billing demand, similar to used in its electric tariff. AIU's math regarding its hypothetical customer's usage is also suspect, which GFA implies calls into question the rest of AIU's analysis.

c. Staff Position

Staff does not object to AIU's proposal to apply the AmerenIP usage-based availability criterion to the GDS-2, GDS-3, and GDS-4 rate classes of AmerenCILCO and AmerenCIPS. Staff states that the modifications provide more uniformity in the gas rate class structures as well as uniformity with the AIU electric tariffs. Staff believes that the resulting uniformity may also avoid potential confusion. Regarding the bill impacts of this change, Staff finds that the proposed rate class definition changes and resulting reclassifications would result in comparable increases for the majority of AIU customers.

d. Commission Conclusion

The Commission appreciates GFA's concerns, but at this time is not confident that implementation of its proposal is as straightforward as GFA suggests. Specifically, the Commission is concerned that GFA has not provided any rate design, cost allocation, or bill impact analysis in support of its position. AIU's proposal to make the gas rate classes more uniform among the three companies is likely to raise questions for some customers. To risk further complicating any explanation with potential problems that may arise from implementation of GFA's proposal is not in the customer's best interest. While the Commission may entertain different availability criteria in the future, for purposes of this rate case, the Commission finds AIU's proposed revisions regarding non-residential rate classes GDS-2, GDS-3, and GDS-4 for each company reasonable and authorizes the implementation of such.

2. Seasonal Prices for all GDS Rates

a. GFA Position

GFA understands that AIU's gas distribution system is designed to accommodate peak usage, which occurs during winter months. Therefore, GFA recommends that all delivery charges, excluding monthly fixed charges, reflect seasonal prices. Such a proposal benefits typical grain dryers, which use about 80% of their annual natural gas volume during harvest, which is about a two month period. Thus, a typical size grain dryer can expect to use approximately 40% of annual usage in each of two harvest months and approximately 2% of annual usage in each of the other ten months.

With regard to seasonal rates and the GDS-2 tariff, GFA states that AIU seems to recognize the value of encouraging use during the non-winter months of April through November, but fails to recognize that the GDS-5 tariff does not send appropriate price signals to customers small enough that they qualify for service under the GDS-2 tariff. GFA states that a typical grain dryer of the GDS-2 size would never be expected to utilize the GDS-5 tariff because of the proposed high monthly fixed charges. Using the typical usage profile, GFA observes that a GDS-2 grain dryer using 15,000 therms annually under the proposed AmerenIP GDS-2 rate will pay $1,710.00 annually in Distribution Delivery Charges. Because the GDS-5 rate has relatively high fixed monthly charges and is designed for larger customers, however, GFA points out that the proposed GDS-5 rate annual charge for this same GDS-2 grain dryer would be $5,377.50. GFA states that a small GDS-2 grain dryer would not be expected to pay over three times the GDS-2 rate delivery charges to avail itself of the off-peak provisions of the GDS-5 rate like larger GDS-3 or GDS-4 customers may do. Although the GDS-5 off-peak provisions is an excellent way to increase off-peak system utilization, GFA asserts that the proposed GDS-5 rate needs to include levels of fixed monthly charges which are comparable to the respective GDS-4, GDS-3, and GDS-2 rates. To address this concern, GFA suggests that AIU could have a second tier lower fixed charge within its GDS-5 rate for smaller off-peak customers to encourage greater utilization of its distribution system. Alternatively, GFA states that AIU could adopt GFA's recommendation of making the availability limit of the HADU of 200 therms or less be applicable once annually for only the billing months of December through March when system daily maximum usage is greatest.

In response to AIU's assertion that it designs its gas distribution systems to carry the peak needs of its customers regardless of the time of year in which they occur, GFA argues that a more important consideration for seasonal rates than maximum annual design capacity is how price signals can maximize utilization of the system through interruptible incentives at times of peak system use. GFA appreciates that AIU has recognized the need to have price signals within the GDS-5 rate which encourage customers to interrupt when the temperature is below 25 degrees. GFA maintains, however, that AIU has provided no data to support not also having a cost-based distribution seasonal rate within its GDS-2, GDS-3, and GDS-4 rates, particularly for the GDS-2 small customer rate for which the temperature-based GDS-5 rate is of no practical value.

GFA states further that AIU has missed the fundamental point that the fixed costs of building a distribution system are correlated with the capacity of the system. That is, the system capacity is determined by its pressure and pipe size. GFA avers that customers who are willing to be interrupted or do not use the system at time of system peak loads of other firm customers certainly reduce overall system average fixed costs. GFA does not propose the extreme referred to by AIU that customers using the system during non-peak periods pay nothing towards fixed costs. GFA, however, does recommend that not just larger interruptible or seasonal-use GDS-3 and GDS-4 customers have access to a seasonal-based or temperature-based tariff such as the optional GDS-5 rate, but that GDS-2 customers also have a similar option, either within the GDS-2 tariff or feasible access to the GDS-5 tariff.

GFA disagrees with AIU's argument that typical GDS-2 size customers do not affect reliability of the distribution system during periods when space heating load occurs, but that GDS-3 and GDS-4 customers can have a profound negative impact on system reliability during periods when peaks occur. GFA asserts that the aggregate load of a group of GDS-2 customers can equal or exceed the load of a GDS-3 or GDS-4 customer. GFA‘s position is that prices in tariffs for GDS-2 size customers should provide similar incentives as tariffs for GDS-3 and GDS-4 size customers: to utilize the system during non-peak load periods and not to utilize the system when heating loads are at or near peak. That can be accomplished, GFA concludes, through either making the GDS-5 tariff feasible for GDS-2 sized customers and/or by implementing seasonal prices within the GDS-2 tariff.

b. AIU Position

AIU contends that GFA‘s position is based on its misplaced belief that AIU‘s distribution system is only designed to carry the utilities‘ overall winter peak usage. In fact, AIU states, it designs its systems to support the peak needs of its customers, regardless of the time of year in which they occur. If the sole design criteria were based on system peak usage during the winter months, AIU contends that off-peak gas users (like GFA‘s members) would have insufficiently sized facilities to support their operations, since their winter gas usage is either minimal or non-existent. AIU argues that GFA‘s recommendation is inconsistent with the principles of system design and the recovery of system investment costs.

AIU asserts that the GDS-5 tariff is the tariff most applicable to GFA‘s members. The GDS-5 tariff reflects the different impacts seasonal-use customers have on costs associated with gas delivery. According to AIU, 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. AIU states that usage by GDS-3 and GDS-4 customers during periods when peak space heating load occurs can have a profoundly negative impact on system reliability. As a result, AIU continues, the GDS-5 tariff is designed to provide incentives to GDS-3 and GDS-4 customers whose processes enable them to avoid operating during periods of heating loads. AIU acknowledges that GDS-2 customers might not financially benefit from selecting to be billed under the optional GDS-5 tariff, but maintains that this does not inappropriately exclude those customers from the optional GDS-5 tariff because the usage of small GDS-2 customers typically does not affect the reliability of the distribution systems that serve them when space heating load occurs. Accordingly, AIU urges the Commission to reject GFA‘s proposal to implement seasonal pricing provisions for all delivery charges.

AIU is also critical of GFA's proposal because it offers no detail concerning its implementation. Nor, AIU continues, does GFA offer any analysis evaluating the actual financial effects of its proposal. For these reasons alone, AIU believes that GFA's proposal should be rejected.

c. Commission Conclusion

The Commission understands that AIU's non-residential gas customers may take advantage of seasonal rates under GDS-5 at their discretion. Certainly one factor customers would consider in whether to do so is whether it would be financially practical. The essence of GFA's concerns appears to be that under AIU's current tariffs, it is very unlikely that it would ever be financially practical for a GDS-2 customer to make use of GDS-5 seasonal rates. AIU does not deny this possibility, but also contends that such a seasonal rate for GDS-2 customers may not be worthwhile in terms of system reliability. AIU indicates that its primary concern with implementing a seasonal rate is that it helps reduce load when peak space heating load occurs. AIU maintains that GDS-2 customers do not typically affect the reliability of the distribution systems that serve them when space heating load occurs.

The Commission understands GFA's concerns, but is not convinced that modifications concerning seasonal rates are warranted at this time. The record lacks evidence indicating that a seasonal rate for GDS-2 customers would benefit system reliability. Moreover, the record lacks evidence on the impact of GFA's proposal on rate design overall, not to mention how to even implement GFA's proposal. If GFA continues to believe that accommodations should be made for additional seasonal rates, GFA should bring specific proposals, containing tariff language and analysis, for the Commission and other parties to consider.

3. Banking under Rider T - Gas Transportation Service

Those customers who purchase their gas supply from a third party have the gas delivered by AIU under Rider T. Such customers tend to be larger customers with commercial or industrial process load. By way of contrast, sales customers are primarily residential heating load customers.

AIU provides banking service to its transportation customers. Under this service, if a transportation customer delivers more gas in a day to AIU than the customer uses for that day, then AIU will hold – or —bank” – that excess gas until it is needed by the customer. In this way, customers can bank an amount of gas equal to up to ten times its MDCQ under current tariff language. If a customer has a positive balance in its —bank” account, then the customer can call on its bank by using more gas in a day than it delivers in that day. In that situation, AIU would make up the difference by using its storage, line pack, or imports from off-system resources. To be clear, gas used from a bank is not gas "borrowed" from the utility; it is gas owned by the transportation customer. The costs of providing the banking service are recovered through base rates as part of the distribution service.

a. Staff Position

Staff recommends that the Commission require AIU to work with Staff and other interested parties (1) to develop an equitable allocation process for storage assets, (2) to allow customers to select the level of banking that best suits their needs, and (3) to develop an equitable allocation of the costs of providing those services. Staff proposes that workshops be held to examine these issues. Staff further recommends that AIU be required to propose in its next rate case tariffs consistent with these goals using language agreed upon in the workshops.

To accomplish these goals, Staff believes that it is necessary to unbundle banking service. Staff defines bundling as the practice of a seller selling several services together for one price. Therefore, unbundling allows individual customers to buy only the services that they desire and at a level that best meets their needs.

Staff explains that under Rider T, banking services are bundled with distribution service and costs are allocated based on peak day deliverability. In comparison, Staff reports that Nicor, Peoples, and North Shore offer banking to their transportation customers without bundling those services with base rates. In fact, Staff continues, amongst these large utilities, only AIU prevents transportation customers from selecting a level of bank capacity that meets their individual needs. Staff adds that other utilities allocate their seasonal capacity equitably to reflect their assets. Staff recommends that AIU provide banking in a manner similar to the way Nicor, Peoples, and North Shore do.

While AIU recognizes some merit in such proposals, Staff notes that AIU has some concerns about expanding bank size. AIU has commented that expanding bank capacity could create a subsidy from sales customers to transportation customers because capacity might not be available and if it is, it would be more expensive. Although Staff supports allowing a subscribable bank, it suggests that the total capacity available should be limited to a proportional level of seasonal capacity in a manner similar to the way Nicor limits bank capacity. The size of the individual customer's allocation should be constrained as well, according to Staff. To protect against exorbitant prices for transportation customers based on off-system storage assets, Staff further recommends that the Commission order that the unbundled Rider T bank be based on on-system storage assets (like Nicor) or total system assets (like Peoples).

Regarding the size of any unbundled bank, Staff notes that in AIU's previous rate cases, the Commission found that a 10-day MDCQ bank is an appropriate size for each of the three gas utilities despite each having different storage capacity. Staff contends that each of the three companies' bank size should be related to their respective storage capacity. Staff also maintains that whatever bank size is eventually adopted, the capacity should be notably larger than ten days of MDCQ. Using the seasonal capacity allocation methods of Nicor and Peoples to show that the proportional capacity is very similar to the AIU systems, Staff calculates that AIU's total system capacities, relative to peak day needs, are comparable to the other utilities. This evidence shows that, while AIU has less capacity in an absolute sense than Nicor, Peoples, and North Shore, a similar allocation method would yield banks significantly larger than the current level. Staff points out that Peoples, which has just a single on-system storage field, and North Shore, which has no on-system storage, both offer relatively large banks when compared to AIU despite the fact that AIU has numerous on-system storage fields that provide more flexibility.

In determining the appropriate bank size for each of the three companies, Staff is also concerned about the allocation being done equitably. Staff disagrees with AIU's contention that the ten-day MDCQ banks are fair and equitable because transportation customer banks have increased significantly since the last case. Staff asserts that this change is the result of customer migration from sales to transportation service since the last rate case.

Nor does Staff find any merit in AIU's claims that (1) there is no demand for unbundling the Rider T bank, (2) it is too soon to consider changing the current tariffs, and (3) increasing bank sizes will result in an allocation away from sales customers to transportation customers. Staff states that CNE-Gas has expressed support for allocating storage assets using the methodologies the Commission approved for Nicor and Peoples, which unbundle banks from base rates, allow transportation customers to select a level of banking they need, and ties cost recovery to the selected bank level. Staff adds that IIEC, another transportation intervenor, states that its member companies would "likely" be supportive of these same issues in its responses to Staff data requests DAS 9.1-9.3. In response to AIU's claim that there is insufficient experience with the current banking provisions to support a change at this time, Staff notes that AIU is actually reducing its off-system storage capacity, which indicates to Staff that AIU has not had a difficult time supplying the increased bank capacity provided through the Commission's prior rate order. Staff denies that its proposal will create a subsidy from sales to transportation customers. In contrast, Staff argues that its proposal corrects the inequity that occurs when a customer must give up storage when switching to transportation service as transportation customers receive too little storage. Staff explains that sales customers benefit from storage assets both in terms of meeting peak day requirements as well as seasonal hedging regardless of their size. If a sales customer loses all or part of that benefit when they switch to transportation service, Staff maintains that they will be unduly deterred from transportation service.

Staff seems to suggest that once at the workshops, the participants should use the bank capacity calculation methods of Nicor or Peoples/North Shore to determine appropriate bank sizes for the AIU systems. Peoples and North Shore use a method that allocates the total system storage capacity (on- and off-system) divided by system deliverability on a peak day. Staff conducted a comparative analysis and found that if AIU were to allocate its storage using the Commission-approved method used by Peoples and North Shore, transportation customers' allocation would be 37, 35, and 27 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. Nicor allocates total on-system storage capacity divided by the peak design day demand. Staff determined that if AIU were to allocate its storage using the Commission-approved method used by Nicor, transportation customers' allocation would be 24, 11, and 24 days of MDCQ for AmerenCILCO, AmerenCIPS and AmerenIP, respectively.

Despite objecting to the use of the Nicor or Peoples/North Shore methods, Staff contends that AIU has presented no clear reason to support its objections. According to Staff, AIU's witness on this issue, Kenneth Dothage, appears to be unfamiliar with the methods utilized by the other gas utilities. Moreover, Staff notes that he attempts to impose operational significance on these results. This is something that Staff does not propose or even suggest, and something that the Commission does not do. Staff asserts that it, Nicor, Peoples, North Shore, and the Commission all understand the purpose of these bank sizing calculations and the logic behind why such calculations makes sense. Staff adds that these methods have not even been contested in other gas utilities' rate proceedings.

In comparing the cost allocation methods, Staff states that a peak day allocator favors sales customers. Smaller customers generally have usage that is largely influenced by heating load and is therefore more weather sensitive. Thus, Staff continues, they represent a relatively larger portion of peak day demand relative to annual usage than transportation customers who tend to include larger process load customers. Therefore, transportation customers' share of annual use is greater than their share of peak day use. If capacity is allocated to individual customers based on their peak day usage (or MDCQ) or the ―days of bank" and allocate underground storage costs based on peak day deliverability, then Staff believes that it makes sense to divide the seasonal bank capacity into peak days. While Mr. Dothage objects to using a peak day allocator and claims that the annual capacity and peak day demand are not related, Staff notes that AIU witness Normand uses a peak day allocator to allocate annual underground storage costs to transportation customers.

Staff advises the Commission to be wary of AIU's claim that bank unbundling may be hampered by (1) a lack of additional off-system storage and/or (2) off-system storage that is only available at a higher cost than existing assets. Staff states that these claims are similar to arguments made by AIU in its last rate cases. (See Docket Nos. 07-0585 - 0590 (Cons.), Ameren Ex. 30.0) After imposing a bank size equal to ten times a customer's MDCQ, however, Staff points out that these fears went unrealized.

Staff explains that AIU's fears failed to materialize because migration of customers from sales to transportation service reduces AIU's peak day or seasonal storage requirements. The reason for the decrease is that transportation customers must deliver most of their peak day usage from the interstate pipelines, getting the remainder of their needs from their banks using AIU's storage resources. In contrast, a sales customer receives his entire supply from AIU either through AIU's deliveries into its systems or from on system storage assets. Staff adds that net migration is overwhelmingly from sales service to transportation service. AIU identifies only one instance of a customer moving from transportation service to sales, which resulted from the elimination of a unique transportation service. Staff states further that it seems very likely that its proposals will make transportation more attractive to customers and that net migration to transportation service will continue.

With regard to AIU's claim that additional off-system storage capacity would be necessary but unavailable, Staff points out that after increasing the bank size in the prior rate cases, AIU is now reducing its off-system storage capacity. This is so, Staff observes, even though the storage capacity devoted to AmerenIP transportation customers increased over 450% following AIU's last rate Order. Staff reports that the only change in AmerenIP's off-system storage was a reduction of 15% in its Mississippi River Transmission storage contract level. AmerenCILCO and AmerenCIPS experienced similar results. In response to AIU's claim that it could not currently obtain additional off-system storage if it needed it, Staff contends that this is not surprising since capacity is usually not available during the withdrawal season.

b. AIU Position

AIU notes that the current bank size provisions went into effect in October 2008 and claims that insufficient data exists to make an informed decision that would warrant any material changes to the balancing or metering requirements. AIU has not recommended any operational changes to the transportation services. AIU notes, however, that Staff makes two recommendations with regard to the bank size. First, Staff recommends that bank service be unbundled from base rates as part of AIU's next rate cases and that bank service be provided as a subscription service. Second, Staff recommends that the Commission determine the bank size in the next rate cases based on a specified methodology. AIU agrees that these issues should be addressed in its next rate cases and has agreed to participate in the public workshops proposed by Staff. AIU would welcome the input at the workshops of all those interested. AIU, however, urges the Commission to not implement any changes to the Rider T banking program as part of these rate cases.

If the Commission directs that workshops be held on these issues, AIU recommends that it refrain from mandating specific tariff or rate structures or otherwise inhibit the workshop process. According to AIU, the workshop process will be best served by letting the participants determine the nature and scope of the discussions. An unfettered workshop process, AIU continues, will permit the participants to identify the unbundling structures that best serve AIU and the customers. AIU adds that any interested party can present alternative positions in the next rate cases if they wish.

With regard to the concept of allowing transportation customers to determine the size of the bank that they desire and are willing to pay for, AIU asserts that a reasonable approach to follow in the workshop process would be to first identify the available resources needed to support the bank service, determine the price/cost of the resources, make the service available at a specified price, and then let the customer elect a certain level of bank service. AIU states that it would be inconsistent to allocate a fixed amount of capacity to all such customers and permit each to choose the amount of capacity it desires from that fixed amount until the fixed amount is spoken for. AIU maintains that the Commission should not address the merits and applicability of the Nicor and Peoples methods in this case. Likewise, the Commission should not limit the workshop discussion to the Nicor or Peoples methods.

In response to Staff's suggestion that the Peoples and Nicor methods should be used to guide the determination of the appropriate size of the Rider T banks in the workshop process, AIU argues that they produce meaningless results when applied to AIU and should be rejected. AIU alleges that the methods have material defects that may not have been identified in previous Commission proceedings. AIU maintains that the Commission should not require it to follow either of these methods simply because they have been previously used by other utilities, without first reviewing the results of their application to AIU. AIU relates that the Peoples method divides the utility‘s total storage capacity by the utility‘s system‘s total deliverability on a peak day. The Nicor method divides the on-system storage capacity by the system‘s total deliverability on a peak design day. Both methods purport to arrive at a number of days of peak deliverability. AIU contends that the defect of both methods is that there is no relationship between the numerator of the equation (storage capacity) and the denominator (peak day deliverability of the system). AIU asserts that the methods are merely mathematical calculations that do not speak to the operational issues or system constraints. The methods, AIU continues, do not show any real relationship between the seasonal working inventory of the storage field and the system peak day deliverability. One is an inventory volume over the entire five month winter season, while the other is a daily deliverability volume. AIU states that dividing the two produces a mathematical result, but that result does not have a rational meaning in the real world of physical deliverability and capacity.

AIU states that Staff‘s suggestion that the Commission consider the Nicor and Peoples models in the future might result from a failure to appreciate the difference between a storage field‘s peak day deliverability and its total storage capacity. A storage field can not release 100% of the gas in storage on the peak day. As an example, AIU states that AmerenCILCO‘s on-system storage has a total capacity of 8,172,473 MMBtu, but AmerenCILCO can only withdraw 190,000 MMBtu from those fields on a peak day. While there is some relationship between the peak day withdrawal capabilities and total system peak day deliverability, AIU argues there is no relationship between the total storage capacity and total system peak day deliverability.

AIU further argues that determining the unbundled bank size using either of the Nicor or Peoples methods will have a negative impact on the system sales customers because any additional seasonal storage capacity that is allocated to support additional days of banking for the transportation customers ultimately will be seasonal storage capacity taken away from the system sales customers. If it must provide additional days of banking rights to the transportation customers, AIU claims that it will have to acquire new seasonal storage capacity for their sales customers to replace the storage allocated to the increased banking service. AIU indicates that the availability and cost of additional storage capacity is unknown. AIU claims that its 821,300 sales customers could suffer for the benefit of its 481 transportation customers. AIU adds that in order to unbundle appropriately the Rider T banking service, a portion of each gas supply system resource would need to be carved out and packaged in a separately priced banking service.

c. IIEC Position

IIEC strongly supports the concept of workshops prior to AIU‘s next rate proceeding to discuss unbundling Rider T's bank from base rates and determine equitable methods of allocating both storage capacity and costs. IIEC is particularly interested in Staff's recognition of the need to coordinate changes in capacity rights with cost allocation procedures. Unless both aspects of the rate design process are treated consistently, IIEC states that there is no guarantee that customers will truly realize any unbundling of assets approved by the Commission.

d. CNE-Gas Position

CNE-Gas supports bank unbundling and notes that in 2008 it urged the Commission to study the utilization of the Nicor and Peoples bank allocation methodologies in order to more equitably allocate assets between sales and transportation customers. CNE-Gas further suggests that the existing bank limits are inequitable and contends that AIU has provided no empirical evidence to support retention of ten days of storage for transportation customers based upon its actual storage assets. CNE-Gas requests that the Commission remedy the existing inequitable allocation of storage assets. Illinois utilities, CNE-Gas continues, have used one of two Commission-approved methodologies for a number of years and both are viable options. At minimum, CNE-Gas states that the Commission should direct AIU to review its current storage allocation methodologies in order to assure equitable storage allocation between sales and transportation customers. CNE-Gas adds that AIU should be required to work with Staff and other interested parties to develop a proposal to unbundle storage for transportation customers that will be included in AIU's next rate case filing.

e. Commission Conclusion

At the outset, the Commission wishes to assure all parties that it will not be directing any changes to the banking provisions of Rider T in this Order. All parties appear to agree that workshops should be held prior to AIU's next gas rate cases for the purpose of discussing alternatives to AIU's current banking terms and conditions. The Commission favors this approach as it may reduce the number of contested issues in AIU's next gas rate cases.

As for the subject of the workshops, which should be open to all those interested, the Commission notes less agreement by the parties. While Staff proposes that specific methods employed by other Illinois gas utilities be considered and modified for use by AIU, AIU urges the Commission to refrain from limiting discussion in any way. The Commission finds merit in Staff's proposal since it concerns methods which it is familiar with and would promote consistency among the gas utilities operating in Illinois. Customers with facilities served by differing gas utilities are apt to find such consistency attractive. AIU's view, however, deserves consideration as well. By directing that the workshop participants develop tariffs implementing the same banking provisions of Nicor, Peoples, and North Shore, the Commission fears that it would be making a decision before having all of the facts. In light of AIU's arguments, enough doubt exists over whether the practices of Nicor, Peoples, and North Shore are appropriate for AIU that the Commission is not comfortable with limiting the workshop discussions.

To resolve this issue in a way that would be most beneficial to its ability to address these questions in AIU's next gas rate cases, the Commission directs AIU and Staff to participate in workshops which will at a minimum result in tariffs implementing for AIU the banking provisions currently employed by Nicor, Peoples, or North Shore. Said tariffs are to be provided in AIU's next gas rate cases. AIU is also free, however, to raise at the workshops its concerns about adopting such banking provisions. AIU may submit in its next gas rates cases as an alternative to what Staff seeks tariffs implementing banking provisions that AIU believes are appropriate. The workshops shall be open to any other stakeholders wanting to participate. The Commission expects all participants to take AIU's concerns seriously. By requiring proposed tariffs implementing either the Nicor or Peoples method but also giving AIU the option to offer an alternative, the Commission preserves for itself flexibility in determining the most appropriate banking provisions under Rider T for AIU. Nothing in this conclusion should be read to prohibit any other party in AIU's next case rate cases from proposing other banking provisions.

E. Contested Electric Issues

1. Overall Rate Design

a. AIU Position

AIU‘s overall rate design utilizes a cost basis as a starting point, applies a rate mitigation approach to the cost basis, and adjusts rates among classifications in an attempt to comport with its own goals as well as those expressed by stakeholders and the Commission. While changes to the DS-1 and DS-2 rate classes are not contested issues in this proceeding, AIU states that the changes are an important component of its overall rate design. Specifically, AIU seeks to conform its rate design to the Commission‘s Order in the previous rate case with respect to DS-1/BGS-1 space heat customers. AIU also seeks to move closer to rate uniformity among the three companies. To do so, AIU modified its DS-1 rates, in order to move towards a —Straight Fixed Variable” or —SFV” approach. Under the proposed rates, AIU will recover approximately 39% of allocated delivery service charges through the customer and meter charges, an increase from the current rates. The change to the BGS-1 supply rate structure compliments this approach and refines AIU's approach to rates for customers using electric space heating. AIU states that the changes to BGS-1 are complimentary to the changes to DS-1. Rates for classes DS-2/BGS-2 are also realigned in this manner.

AIU also proposes changes to general service (DS-3) and large general service (DS-4) customers. The rate design for these classes remains a contested issue. Similarly, rate design for lighting customers (DS-5) remains a contested issue.

AIU recognizes that the Commission is unlikely to approve its requested revenue requirement without change. The conformance of the final rates to the adjudicated revenue requirement is an essential task in this case. AIU proposes that the final rates be adjusted to meet certain rate design objectives, which AIU contends provides a better balance between movement toward cost-based rates and mitigating bill impacts. AIU states that its approach recognizes that simply shifting rates based on some percentage places disproportionate rate burdens on certain customer classes. Specifically, AIU proposes to retain all Customer, Meter, Transformation, and Reactive Demand charges for all the rate classes. Then, for DS-1 and DS-2 classes, AIU would adjust Distribution Delivery Charges based on a uniform percentage, in order to achieve the final rate requirement. For the DS-3 class, AIU proposes to achieve final revenue targets through a uniform percentage reduction to the $/kW Distribution Delivery Charge for each of the companies. Finally, for the DS-4 class, AIU proposes to adjust the new variable Delivery Charge to a level to match the revenue target, but not lower than one half of the average PURA tax amount. If necessary, AIU would also lower the DS-4 $/kW Distribution Delivery Charge in order to achieve the revenue allocation target. AIU reports that its approach has been used by the Commission in the past. (See, e.g., Docket No. 91-0335 at 70-72; Docket No. 93-0183 at 90-107; and Docket Nos. 99-0120/99-0134 (Cons.) at 64.)

While Staff's and IIEC's across-the-board approach to conforming rates with the final revenue requirement is easy to administer, AIU maintains that their approach misses an opportunity to address subsidy elimination, rate continuity, and bill impact concerns. The Staff and IIEC approach, AIU continues, also misses an opportunity to better address concerns raised by various parties in this case. For example, AIU contends that Staff's approach exacerbates a problematic divergence between DS-3 and DS-4 delivery rates and, as such, fails to address this important concern. Because such an oversimplified approach strays from the goals of cost-based ratemaking and mitigating bill impacts, and AIU's approach embraces those goals, AIU asserts that its rate design approach should be approved by the Commission in this docket.

b. Staff Position

Staff generally supports AIU's rate design for the BGS classes and DS-1 and DS-2 classes, but disagrees on how the DS-3, DS-4, and DS-5 rates should be designed. Given the Commission's stated preference for SFV rate design, Staff considers AIU's proposals for the DS-1 and DS-2 rate classes acceptable in this case. Staff considers AIU's proposals to be a reasonable solution to the challenges posed by the rate redesign conducted in Docket No. 07-0165. In that proceeding, the Commission faced a common problem of disproportionate bill impacts for customers with high consumption levels in non-summer months. For each class, the problem was addressed by reducing BGS supply charges for higher usage blocks in the non-summer months and increasing other BGS charges accordingly. These adjustments in Docket No. 07-0165 have created a discrepancy between supply charges and costs. To reduce these imbalances, Staff relates that AIU proposes to move tail block non-summer rates closer to costs.

While Staff suggests that the Commission consider raising non-summer tail block rates for the DS-1 class, it does not make a similar proposal for DS-2 customers. Staff explains that it does not do so because the gap between BGS charges and costs for bundled DS-2 customers in the non-summer tail block is not nearly as great as for residential DS-1 customers. For some residential customers, the current per kWh tail block supply charge falls to one cent or below, while for bundled DS-2 customers the charge remains above 4¢/kWh. Staff states that this much smaller gap between supply charges and costs for residential space heating tail block usage provides the reason to suggest that the Commission consider going further than AIU proposes to raise that supply charge for residential customers.

With regard to conforming the final rates with the final revenue requirement, Staff prefers to lower all DS components to achieve the final revenue requirement allocated to a class. In order to accomplish that goal, Staff recommends adjusting the rates that are uniform among the three companies – Customer, Meter, Transformation, and Reactive Demand Charges – on a combined AIU basis, and then adjusting the remaining rate components by an across-the-board amount to achieve the desired revenue target. Staff favors its rate adjustment methodology over AIU's because it considers its own method simpler to implement.

Staff adds that compliance rates are not a good place in which to adjust rates for specific rate design objectives. Any changes to rates at that juncture have important implications for all AIU ratepayers. To the extent that one rate element is adjusted and another is not, Staff fears that certain ratepayers will benefit while others will be disadvantaged. The problem, Staff continues, is that no ratepayers have recourse at this stage of the process. If a group of customers loses out, Staff states that they must wait until the next rate case to seek redress. In contrast, Staff observes that its equal percentage adjustment approach to compliance rates has the same impact on all ratepayers. Staff points out that ratepayers will know they receive the same treatment as everyone else in the adjustment of their rates to the final revenue requirement. Staff contends that this is more transparent and equitable.

c. IIEC Position

With the three exceptions of (1) AIU's proposed collection of PURA taxes through a new line item charge on customers' bills, (2) the combination of the DS-3 and DS-4 classes for Distribution Delivery Charges, and (3) the failure to allow for combined billing for multiple meters on the same or adjacent premises, IIEC does not oppose the basic rate structure and design used by AIU, which are mostly consistent with prior rate determinations. IIEC, however, does have some concerns regarding how to conform the final rates with the approved revenue requirement. The problem with both Staff's and AIU's approach, IIEC argues, is that they begin with AIU's flawed COSS, which are used to develop class revenue allocations under both of their proposals. IIEC complains that adjusting proposed rates downward on a full across-the-board basis, as proposed by Staff, or by a constrained across-the-board basis as proposed by AIU, will maintain the underlying class and subclass revenue allocations proposed by each.

Since these revenue allocations are based, at least in part, on the flawed cost studies, IIEC asserts that they result in the same objectionable revenue shifts between classes. To address such concerns, IIEC recommends starting with current rates and adjusting rates upward on an across-the-board basis to meet the utility revenue requirements, which would result in minimal or no cost shifting between classes.

If the Commission accepts AIU's COSS for revenue allocation and rate design purposes and decides to increase rates from current rates on something other than an across-the-board basis as recommended by IIEC, IIEC originally suggested that the Commission order AIU to rerun its COSS and determine class and subclass revenue allocations in accordance with the Commission's findings in this case. In that event, IIEC supported Staff's method to adjust downward the resulting rates on an across-the-board basis to conform the rates to the final utility revenue requirements. If, however, the rerun cost studies also reflected the final approved utility revenue requirements, IIEC stated that no downward scaling would be needed.

IIEC originally preferred Staff's position over AIU's if its own was not adopted at least in part because it found AIU's approach to final rate conformance unclear. After having reviewed AIU's Reply Brief and giving AIU's approach more consideration, however, IIEC now favors that approach if the Commission does not accept IIEC's position on the PURA tax and allows AIU to establish a new tax line item on delivery service bills. IIEC believes it would be appropriate to reduce the charge associated with that new line item as much as possible in order to conform rates to class or subclass revenues resulting from lowering the revenue requirement. If AIU's position on the conformance of rates to the approved revenue requirement includes lowering the proposed DS-4 PURA tax charge as described by AIU witness Jones (see Ameren Ex. 40.0 Second Revised at 15-17), IIEC now supports AIU's proposal if its positions on the relevant issues are not adopted by the Commission. While Staff's approach does not address the onerous PURA Tax charge, it is IIEC's understanding that AIU's approach does. IIEC, however, believes that AIU has not provided justification for limiting the reduction in the charge to one-half of the PURA tax amount as recommended by Mr. Jones, and therefore recommends that the artificial limitation be eliminated, allowing the tax charge to be reduced as much as needed to conform the class or subclass rates to the reduced revenue requirement.

d. Commission Conclusion

Except as modified below, the Commission generally finds AIU's electric rate design acceptable. In addition to the modifications set forth below, however, the Commission must also determine to what extent the overall rate design should change to reflect the final revenue requirement adopted in this proceeding for each electric utility. As discussed above in the context of cost allocation, the Commission does not find AIU's electric COSS fatally flawed and will therefore not be implementing an equal percentage across-the-board change to reflect the final revenue requirements. Instead, after rerunning the COSS as directed above, adjustments will need to be made reflecting the difference from AIU's proposed revenue requirements and the approved revenue requirements.

Despite some ambiguity and changing positions, the Commission believes that it understands the positions of AIU, Staff, and IIEC. The Commission finds that a simple approach in this situation is preferable. As proposed by AIU, the Customer, Meter, Transformation, and Reactive Demand charges for all of the rate classes should be retained. Any change in the revenue requirements should then be reflected through a uniform percentage reduction in the Distribution Delivery Charges for the DS-1 through DS-3 rate classes, which is consistent with what the Commission understands AIU to be proposing for these rate classes. For the DS-4 rate class, AIU's proposal appears to be a form of rate mitigation for larger customers. The proposal appears reasonable and as it is endorsed by IIEC, the Commission accepts it for purposes of this proceeding. The Commission finds AIU's proposal in this context for the DS-5 class acceptable as well.

2. Rate Moderation/Mitigation

In order to establish a rate design, AIU and Staff utilized the results of their respective electric COSS methodologies and applied mitigation strategies to underlying cost indicators. Given its concerns with AIU's COSS, IIEC developed a mitigation strategy separate from a COSS. Those mitigation strategies serve an important role in promoting rate continuity and rate stability while considering potential bill impacts that could result as rates are moved toward the actual cost of service.

a. AIU Position

AIU proposes to mitigate bill impacts resulting from this rate case by limiting the increases to rate classes DS-1 through DS-4 to 125% of the system average increase, excluding the DS-5 class and the PURA tax. AIU excludes the PURA tax from its rate mitigation calculations because it is assessed to utilities on a kWh or energy basis, which leads AIU to believe that the tax should be assessed to customers in the same manner, without effectuating cross-subsidies that would otherwise invariably be created by rate mitigation strategies. According to AIU, Staff acknowledges that the ultimate effect of “mitigating” cost assignments by including the impact of the PURA tax assessed to utilities would be subsidized rates. Staff further acknowledges, AIU adds, that using AmerenCILCO as an example, DS-2, DS-3, and DS-4 customers would be receiving a subsidy on a class total revenues basis, inclusive of a portion of the PURA tax associated revenue requirement. AIU therefore concludes by the process of elimination that the incremental effect of including the PURA tax in a rate mitigation approach serves to increase the subsidy burden imposed upon residential (DS-1) and lighting customers (DS-5). AIU argues that it is intrinsically unfair to hold residential and lighting customers responsible for tax liabilities that would not exist but for the kWh usage of larger customers. In other words, AIU does not believe that it is appropriate to collect tax costs from any ratepayers other than those that created the tax obligation. AIU claims that its proposed revenue allocation approach provides a better balance between movement toward cost-based rates and mitigating bill impact.

In response to Staff's proposal to constrain rate increases to 150% of the overall average, including the PURA tax, AIU argues that doing so would put a disproportionate burden on classes DS-3 and DS-4, and, consequently, widens the gap between DS-3 and DS-4 on a dollar per kW demand charge basis. Even if the Commission adjusts the revenue requirement downward due to proposals by the parties, AIU states that the relative differences and relative magnitude of the difference remains the same. AIU maintains that the disproportionate burden created for the DS-3 and DS-4 rate classes under this approach moves away from the stated goal of cost-based rates and mitigation of bill impact. Regarding Staff's concerns for the DS-5 class, AIU defends the fixture charges as promoting rate uniformity across the three utilities, consistent with the Commission's Order in AIU's last rate proceeding.

In response to IIEC's proposal to limit increases (if rates are based on AIU's COSS) to the overall average plus 25% for each class or subclass, inclusive of the PURA tax, AIU contends that the problem with this proposal is that it defines —subclasses” based on the customer‘s supply voltage and customers often use more than one voltage. AIU points out that many customers take service supplied at a higher voltage than that delivered and metered. AIU urges the Commission to reject IIEC‘s proposed rate mitigation method because it is lacking in both detail and guidance.

AIU suggests further that IIEC does appreciate AIU's obligation to consider both its large and small customers when it developed its rate mitigation proposal. So, to the extent that a small number of customers experience a larger-than-average rate increase, AIU contends that those increases are consistent with the principles of rate mitigation. AIU asserts that its proposal is simply the most equitable for the rate classes, collectively.

AIU also acknowledges the concern expressed about bill impacts on small customers and maintains that such concern is justified. After power supply price increases followed AIU‘s emergence from a ten-year rate freeze in 2007, it had to redesign its rates in Docket No. 07-0165, in order to address rate continuity issues. As a result of that proceeding, and the rate increases that resulted from it, AIU states that it must examine rate design changes for small customers carefully. On the other hand, however, AIU states that it also considered bill impacts to large customers, as evidenced by the fact that its proposed mitigation strategy utilizes a 125% revenue allocation constraint for all the customer classes, including DS-4.

Additionally, IIEC contends that AIU‘s rate moderation approach is inappropriate because AIU examines bill impacts on a total bill basis. Instead, IIEC contends that AIU should consider only the Distribution Delivery Charges when determining rate impacts. AIU counters that doing so would not provide it or the Commission with an adequate indicator of true bill impacts on customers. Instead, AIU continues, IIEC‘s approach benefits customers who currently have low delivery service rates, because any substantive increase to those rates results in a much higher percentage increase. AIU maintains that its total bill approach is the only way to truly understand bill impacts here.

AIU attempts to demonstrate its point by way of an example using postage delivery rates. AIU asserts that delivery charges, whether they are for a parcel or electricity, are a concern for consumers within the context of the overall bill or transaction. If an individual is thinking about ordering merchandise for home delivery, the impact of the shipping charge is relevant within the overall context of the economics presented by the transaction. According to AIU, a consumer would not exclude the price of the merchandise in deciding whether the shipping rates are unreasonable. If a person is debating whether to order a $1000 oil painting, and the gallery decides it will increase its shipping charges from $30 to $60 dollars, the purchaser is confronted with a total price for the item that has increased by approximately 3%. On the other hand, if the customer is purchasing a $50 reproduction print, the differential in the shipping price becomes more material to the customer's economic choices. AIU believes that this example shows that examination of total bill impacts is a common sense approach.

b. Staff Position

Staff proposes to allocate electric revenues according to their underlying costs subject to the limitation that no class would receive an increase greater than 150% of the system average increase. While Staff contends that its proposal appropriately balances costs and bill impact concerns, it maintains that AIU's alternative proposal to limit increases for any individual class to 125% of the system average increase is contradictory and confusing. Staff adds that AIU's proposal excludes PURA taxes from the constraint and thereby produces much larger increases for individual classes.

Staff understands that AIU wishes to mitigate the impact of any rate increase stemming from this proceeding in light of the difficulties ratepayers have encountered in recent years adjusting to electric rate increases. Staff notes that the relative newness of the then current rates during AIU's last rate case contributed to the Commission decision to adjust rates on an across the board basis. Staff further notes that AIU now believes that sufficient time has passed and circumstances have changed enough to warrant taking steps again toward implementing cost-based rates while attempting to minimize rate shock.

The first problem for AIU, according to Staff, is that the rate mitigation constraint it has chosen does not cover costs associated with the PURA tax. AIU appears to believe, Staff continues, that ratepayers will accept disproportionate increases as long as they are tied to PURA taxes. Staff avers, however, that there is no evidence in the record to indicate that customers make such a distinction. Furthermore, Staff finds AIU's approach to rate mitigation contradictory, since logic which would indicate that ratepayers care about all components of their electric bills including PURA taxes.

The second problem centers on AIU's unequal treatment of DS-5 lighting customers. AIU proposes significantly higher revenues for the lighting classes than justified by the underlying cost. Staff understands that AIU bases this proposal on the ostensible objective of making lighting charges more uniform across the three companies. According to Staff, AIU acknowledges that the result of the DS-5 revenue allocation methodology is revenue reductions of approximately $1.97 million, $1.62 million, and $60,000 reallocated to each electric utility's DS-1 through DS-4 classes. Staff maintains that this allocation is unfair to lighting customers who receive a higher increase than justified by the methodology applied to other rate classes. Staff reminds the Commission that lighting bills are paid by municipalities that, in turn, must recover the costs from taxpayers. If lighting rates go up, the higher costs will be borne by taxpayers. Staff believes that the more equitable alternative is to apply the same revenue allocation rules to all rate classes. Staff also rejects AIU's claim that higher revenue allocations are necessary to make progress toward the goal of equalizing lighting rates. While the Commission directed AIU to address the possibility of doing so, Staff contends that considering the possibility is far different from imposing such higher revenue allocations on DS-5 customers.

The third problem, Staff reports, is that AIU's proposed class revenue allocations rest upon a flawed cost of service foundation that features an NCP allocator for primary distribution lines and substations. To the extent that the COSS deviate from cost causation principles due to this error, Staff states that this error will distort the resulting class revenue allocations regardless of the methodology employed.

Staff, like the other parties to this case, states that it is concerned about bill impacts for AIU ratepayers. Staff adds, however, that bill impacts are not the only concern in allocating the revenue requirement. Costs are important as well. Staff believes that the best way to balance these two concerns is through a constrained class revenue allocation. Staff maintains, however, that any effort to address bill impacts in the revenue allocation process must be consistent and fair to all rate classes. Staff contends that its proposed 150% constraint represents a reasoned judgment of how much progress can be made towards cost-based revenue allocations while addressing bill impact concerns. While the Staff constraint is higher than the AIU proposal (150% vs. 125%), Staff points out that its proposal encompasses all costs in the revenue requirement while the AIU proposal exempts PURA taxes. Staff therefore concludes that its proposal is more consistent and equitable.

Staff‘s approach accords the largest percentage increases to the biggest customers on the system. This result is largely driven by the reallocation of costs associated with PURA taxes among rate classes. The shift in allocation of PURA taxes from utility plant to usage shifts responsibility for these costs to DS-3 and DS-4 customers who account for 12% and 43% of sales, respectively. Despite this shift, Staff insists that the proposed increases for these classes will not produce an undue increase in their overall cost of electricity. Utility bills for large customers generally extend to delivery service costs only because they tend to purchase power from non-utility suppliers. Thus, Staff asserts that a significant increase in delivery services does not necessarily translate into a large increase in the overall cost of electricity.

Staff insists that its approach is more equitable for DS-5 customers as well. Staff essentially argues that AIU has arbitrarily increased lighting rates above the cost of service for the sake of consistency among the three utilities. According to Staff, AIU readily admits that it has applied one standard to lighting customers and another to all remaining customers. Staff states that this is clearly unfair to the lighting class. When utilities factor bill impacts into the revenue allocation process, Staff maintains that their approach should be based on a transparent set of rules fairly and consistently applied to all rate classes to ensure that some are not shortchanged in the process. Staff contends that AIU's proposal clearly falls short in this regard.

Staff notes that AIU criticizes its mitigation approach by claiming that a 150% limit puts a disproportionate burden on the DS-3 and DS-4 classes. But later AIU also complains that Staff's approach to distribution taxes would subsidize the DS-3 and DS-4 classes as well as the DS-2 class. Staff therefore understands AIU to argue at the same time that Staff's approach both burdens and subsidizes the DS-3 and DS-4 classes. Staff contends that this confused argument can be readily dismissed by the Commission.

With regard to IIEC's rate mitigation argument, Staff asserts that IIEC's proposals do not appear to satisfactorily address the Commission's concerns about returning the focus of AIU ratemaking to cost of service. Staff recalls from AIU's last rate case that the Commission —finds value in Staff's recommendation that AIU provide gas and electric rates in the next rate cases based on cost of service and directs AIU to do so in the next rate cases." (Docket Nos. 07-0585 et al. (Cons.) (September 24, 2008) Order at 281) Staff contends that neither IIEC's proposed across-the-board allocation nor its limited constraint of 25% over the system average increase at the subclass level appears to be consistent with the Commission's statement.

c. IIEC Position

IIEC complains that AIU is requesting an unprecedented level of rate increases for its largest, highest load factor customers but is doing little in terms of rate mitigation for the affected customer classes and subclasses. IIEC contends that the two main failings in AIU's approach are its failure to reflect the impact of the PURA tax in its analysis and its failure to apply its moderation criteria at the subclass level. In contrast to AIU's proposal, IIEC argues that its approach properly recognizes the cost differences and bill impact differences among subclasses within a customer class, rather than considering only —average" impacts of widely varying increases.

Although AIU claims to have taken into account cost impacts and rate moderation, IIEC asserts that the proposed increases for the customers in the DS-4 class illustrate an unfortunate disregard of the principles of rate continuity and avoidance of rate shock. IIEC notes that in some instances the increase in delivery service charges is in excess of 1,000%. For some customers, this translates to increases in delivery costs of over $1 million per year. IIEC contrasts this result with AIU's position on the rate limiter in this case (discussed below) and its response to delivery service rate increases as high as 42% for certain customers subject to the rate limiter. IIEC maintains that the disconnect between AIU's position on the rate limiter and its attempts to justify unprecedented rate increases as high as 1,000% for other customers makes more apparent its intent to impose as much of its rate increase on its largest customers as possible, in order to avoid adverse political responses to its overall rate request in this case. While the Commission may wish to give favorable consideration to AIU's proposal for extension of the rate limiter for grain drying customers, and if it does, IIEC would not object, IIEC urges the Commission to also give favorable consideration to any reasonable recommendation to reduce the level of the rate increase requested by AIU for all customers, and to the specific recommendations of IIEC on appropriate cost allocation and rate mitigation measures in this case.

IIEC accuses AIU of attempting to mask the level of its proposed increases in DS-4 charges by providing comparative statistics that include costs that have no bearing on the delivery service charges that are at issue in this case. IIEC relates AIU's claim that increases of as much of 100% in the delivery bill are acceptable if viewed from the perspective of a total bill that includes power commodity costs. AIU witness Jones' focus on masking the impacts of increases in delivery service bills is understandable, according to IIEC, since he was instructed to do so by Ameren management. IIEC offers the following excerpts from an e-mail exchange between Mr. Jones and AIU witness Mill on May 17-18, 2009:

> By Mr. Jones: —How comfortable are you and do you think others will be showing a DS-4 increase in the 70% - 90% range (56-30% without the Distribution [PURA] Tax influence)?”
>
> Response by Mr. Mill: —If you were to assume 5 cent power for DS-4, what is the weighted bundled increase for the 70-90%?”
>
> Response by Mr. Jones: —The large percentages do not look as bad when power is included…”
>
> Response by Mr. Mill: —On a bundled basis it looks like the % increases for all but primary are near the average bundled price increases that residential will face. If you go this route, you need to be strong in your testimony re a bundled viewpoint to help soften reactions”
> (IIEC Ex. 1.2, [partial Ameren response to data request IIEC 4.09] – tables omitted)

From this exchange, IIEC believes that it is clear that AIU knew the impact its proposals would have on large customers‘ delivery service bills, including the impacts with and without the PURA tax. But rather than proposing to implement any meaningful rate moderation, IIEC states that AIU chose instead to try to obscure the unprecedented size of its delivery service rate increase to these customers by considering irrelevant costs in its analysis. IIEC insists that costs other than delivery service costs have no bearing on delivery service rates, or the need for rate moderation.

AIU consciously chose to add to the revenue requirement of the DS-4 customers, IIEC continues, in order to benefit the DS-1 residential class. According to IIEC, AIU's strategy is to make the requested revenue increase as palatable for residential customers as possible by shifting cost responsibility to large customer classes. A rate moderation proposal that mutes the impact of the increase on large customers, IIEC continues, might also mute the impact of the revenue shift from residential customers. In an e-mail from Ameren president Scott Cisel to Mr. Jones and Mr. Mill, IIEC states that Mr. Cisel emphasized the need to protect residential customers. In e-mails dated May 25, 2009, IIEC reports that Mr. Cisel makes the following observations:

> "It appears that most of the charges, graphs for residential and small business customers are contained in this exhibit. As we all know, residential and small businesses are lightning rods."
>
> —I want to better understand the proposed rate changes on residential customers and small businesses and how they will play on ‗Main Street'. Good rate design based on the data is important; however if the design causes major public unrest, we will have difficulty in achieving our desired success. Balancing all interest is difficult."
>
> —My intuition tells me without seeing the data a much smaller decrease would seem appropriate for the large usage customers and use the difference to reduce the increase of the lower usage customers."
> (IIEC Ex. 1.0-C at 15)

In addition, in an e-mail dated the following day, May 26, 2009, IIEC relates that Mr. Mill observes, —Scott very concerned re optics and outcry from small customers." (Id.) In light of these comments, IIEC argues that AIU's revenue allocation and class rate increase proposals are not driven by rate making principles such as rate impacts, rate stability, and rate moderation, but by its desire to protect itself from adverse political reaction to its overall increase and to help ensure it receive its desired level of rate relief. IIEC urges the Commission to set delivery service rates that are stable, fair, equitable, and take into account the principles it has espoused in the past and which are present in the Act. IIEC insists that stable rates, that avoid rate shock, are a necessity for all customer classes and subclasses.

To moderate the rates which it complains of, IIEC originally proposed a rate mitigation approach that limits the increase to any subclass' revenues to 25% above the average change in rates of each company's overall increase. But given its concerns over AIU's electric COSS, which came to light in AIU's prepared surrebuttal testimony and cross-examination testimony, IIEC finds itself unable to rely on AIU's COSS to allocate costs and set rates. If the Commission is left without a valid measure of class and subclass cost of service because it can not rely on AIU's COSS, IIEC asserts that it has no basis for shifting revenue responsibility between classes and should implement any increases or decreases to the rates on an across-the-board basis.

IIEC asserts that an across-the-board rate allocation would still address the rate moderation concerns expressed by IIEC and Staff, as the resulting impacts on bills would, by definition, fall within the rate moderation criteria expressed by each. An across-the-board increase in rates affects all classes and subclasses equally, by the percentage increase (or decrease) in revenues. Thus, IIEC states, the 25% above the average increase proposal of IIEC, and the 150% of the average increase proposal of Staff are automatically met. According to IIEC, this approach would also meet the Commission's goal to avoid rate shock and ease rate impacts.

Because of the huge increases that AIU's proposals produce for subclasses within the DS-4 rate class, IIEC maintains that the subclass revenue allocations should include the impact the PURA tax. Should the allocated revenues that result in this case exceed the rate moderation thresholds, IIEC contends that the most reasonable approach to implementing this allocation would be to first spread any revenue deficiencies to other subclasses within a rate class, e.g., DS-4, on a proportional basis, unless and until the 25% above system average threshold is reached for any of the other subclasses. If all subclasses within a delivery rate class reach the maximum of 25% above the system average increase, IIEC recommends spreading any remaining revenue shortfall among the other subclasses, again on a proportional basis. IIEC adds, however, that Staff's rate moderation approach to limit the increase on current rates for any class at 150% of the system average increase approved in this proceeding, including the impact of the PURA tax, would be acceptable, assuming the application is done at the subclass, rather than full class level.

IIEC insists that rate moderation occur at the subclass level since it is the actual bills that customers pay which determine the degree of rate shock. IIEC reports that the bills that the subclasses would pay under the AIU proposed increase in this case are dramatically different, even within the same rate class. IIEC states that the increases in delivery charges vary for the DS-4 class from 35% to 541% for AmerenCILCO, from 24% to 1,270% for AmerenCIPS, and 20% to 760% for AmerenIP. IIEC's point is that, regardless of the final revenue requirement in this case, the actual bills that a customer must pay depends not so much on the class to which it belongs (e.g., DS-4), but on the subclass to which it belongs (e.g., DS-4 100+ kV).

IIEC is also concerned about the effect that recovering the PURA tax as a separate line item will have rate moderation efforts. IIEC maintains that it will be impossible to implement Staff's rate moderation proposal and simultaneously collect an equal PURA tax per kWh charge as a separate line item on the bill. IIEC explains that this is because the PURA tax has such a dramatic effect on the overall delivery service bills of some customer classes and subclasses (See IIEC Ex. 1.0-C at 5: Table 1--showing class increases of about 60% for DS-4 customers; and at 7: Table 2--showing increases ranging from 78% to 131% for DS-4 High Voltage customers and 541% to 1,270% for DS-4 100 kV and Above customers). Using a uniform PURA tax recovery charge for all customers would require that the base delivery service charges for certain customer classes or sub-classes would need to be reduced to zero, or even go negative, which, according to IIEC, is obviously an illogical result. Of the two factors, IIEC argues that adequate rate moderation is far more important than implementing a new line item on a bill associated with a tax that is already being collected in base rates.

Therefore, in order to comply with IIEC‘s, or Staff‘s, rate moderation proposal, IIEC states that the Commission must reject AIU‘s and Staff‘s proposal to collect the PURA tax charges on a ¢/kWh basis as a separate line item and instead, maintain the current recovery of the costs through base rates.

d. Commission Conclusion

It is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism, and avoid rate shock. Given the history concerning AIU's rates and the change in the PURA tax allocation, among other conclusions in this Order, the rate impact on all of AIU's rate classes is of great importance to the Commission. One of the Commission's first observations on this issue pertains to AIU's exclusion of the PURA tax from its rate mitigation proposal. While AIU's reasons for excluding the PURA tax in its proposal are understood, the Commission can not accept them. As argued by Staff and IIEC, the Commission can not agree that customers are not concerned about their bill total as long as increases in individual components are arguably reasonable. Examples may be offered on both sides of the argument, but the fact remains that when it comes time to pay a bill, a customer's budget, whether it be a residential or industrial customer, is impacted by the bill total regardless of the reasonableness of the bill's components. Accordingly, rate mitigation efforts should be looked at from the perspective of the bill total.

Setting aside IIEC's preference for an across-the-board rate change, Staff and IIEC both offer rate mitigation approaches which include the PURA tax. Neither is perfect, but entering an order lacking rate mitigation is not an option. In reviewing the proposals, IIEC's proposal raises a point worth serious consideration. IIEC recommends that rate moderation be implemented at the subclass level. Given the concern over the impact of the change in the PURA tax allocation, the Commission is inclined to agree. Moreover, IIEC has expressed its willingness to accept Staff's rate mitigation approach if it is applied at the subclass level. The Commission sees no reason why Staff's proposal based on a 150% increase limit could not be applied at the subclass level, as suggested by IIEC.

In arriving at this conclusion, the Commission must also find that AIU should recover the PURA tax through a separate line item on bills. The Commission believes ratepayers should be made aware of taxes they are being charged.

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

The DS-3 rate class is comprised of non-residential customers that have billing demands ranging from 150 kW up to 1,000 kW. The DS-4 rate class is comprised of all non-residential customers with billing demands of 1,000 kW or greater. There are four basic categories of charges for DS-3 and DS-4 customers: (1) Customer Charges; (2) Meter charges; (3) Distribution Delivery Charges; and (4) Transformation Charges. In addition, DS-4 customers are subject to a Reactive Demand Charge. The first three categories of charges are differentiated by voltage, e.g., secondary, primary, high voltage, and transmission voltage. At each voltage level, the Customer Charge is uniform between DS-3 and DS-4. Likewise, the proposed Transformation Charge is uniform between DS-3 and DS-4 in each service territory. The Distribution Delivery Charge is a demand charge levied on a per-kW basis, with rates differentiated with respect to voltage level: primary, high voltage, and transmission voltage. There is no separate Distribution Delivery Charge for secondary voltage. Secondary voltage customers pay the primary Distribution Delivery Charge plus the Transformation Charge. Unlike the Customer Charge and the Transformation Charge, the Distribution Delivery Charge is not uniform between the DS-3 and DS-4 rate classes.

a. AIU Position

AIU indicates that customers served at lower voltages require additional investment in distribution facilities as compared to customers served at higher voltages. As a result, AIU states that voltage differentiated pricing reflects the costs incurred to serve customers, and is higher for low voltage customers and lower for high voltage customers. AIU proposes Distribution Delivery Charges that were developed using an approach similar to that used to establish prices for the same elements in AIU's second most recent set of rate cases, Docket Nos. 06-0070 et al (Cons.). The distinction being that in this pending proceeding, AIU combined the demand-related costs for the DS-3 and DS-4 classes and divided by the combined voltage differentiated demands.

AIU argues that its revenue allocation approach should be used to determine the Distribution Delivery Charge for DS-3 and DS-4, as it establishes more consistent bill impacts among customer classes. AIU adds that its approach provides for relatively moderate differentiation between classes when compared to Staff‘s approach. Under Staff‘s approach, AIU states that AmerenIP and AmerenCILCO DS-3 customers take on a greater burden. AIU indicates that Staff‘s approach also unnecessarily provides marginal relief to the DS-4 class for each of the three companies. AIU contends that this issue is important when considering that DS-3 customers with larger demands, or DS-4 customers with smaller demands, may reclassify from DS-3 to DS-4, and vice versa. Under Staff‘s proposal, a customer reclassifying from DS-4 to DS-3 may experience a rate increase if their demand did not drop by an amount more than the price increase. While some difference between the rates is justified, AIU fears that large differences may encourage inefficient use. AIU maintains that Staff‘s proposal widens the gap between DS-3 and DS-4, increasing the potential for such inefficiency. In response to Staff's contention that the greater burden its method places on the DS-3 class will be mitigated to the extent that the Commission adjusts the revenue requirement downward, AIU states that the relative differences in the revenue requirements and price disparity remain. Because its proposed Distribution Delivery Charges for the DS-3 and DS-4 classes are closer together than those proposed by Staff, AIU asserts that its revenue allocation and rate design will produce final rates that are closer together.

Furthermore, AIU contends that its method for determining the DS-3 and DS-4 Distribution Delivery Charge addresses the concerns of many of the parties. For example, AIU states that its rate adjustment approach reduces DS-3 Distribution Delivery Charges, which closes the gap between DS-3 and DS-4 – a concern of Kroger. AIU adds that its method also reduces the amount of rate limiter credits – a goal of GFA. Moreover, AIU asserts that its rate adjustment approach reduces the proposed DS-4 ¢/kWh charge first, and if necessary, the $/kW Distribution Delivery Charge, which is responsive to the concerns of IIEC. Further, both LGI and AIU contend that there is merit in moving toward more uniform Fixture Charges among the three companies – AIU‘s rate adjustment approach moves toward that goal. AIU contends that Staff has overlooked all of these concerns in its approach. Because it considers its proposal directly responsive to many of the concerns of the numerous intervenors, and creates more consistent bill impacts, AIU deems its method preferable to Staff's and urges the Commission to accept it.

In response to Kroger's proposal to bridge the gap between the DS-3 and DS-4 classes by removing 50% of the difference between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment for the DS-4 reactive power revenues, AIU argues that Kroger‘s proposal does not measure potential bill impacts for the affected customers. AIU states that Kroger could have prepared that analysis, but did not. Without further analysis by Kroger, AIU asserts that the Commission can not seriously consider the proposal. AIU also observes Kroger's own acknowledgement that it has submitted the same proposal in three consecutive AIU rate cases with no success. AIU agrees that the DS-3 and DS-4 Distribution Delivery Charges should move closer together, but disagrees that now is the time to take such drastic measures, particularly given the ongoing concerns of bill impact and rate mitigation.

b. Staff Position

Staff understands AIU's proposed rates to include a common set of Customer and Meter charges for the DS-3 and DS-4 classes that are set at current levels. For demand charges, Staff states that AIU first develops a unit cost for demand that applies to both the DS-3 and DS-4 rate classes. Staff understands that that unit cost is then adjusted by AIU to reflect that revenue contributions from the DS-3 class will be slightly less than those for the DS-4 class through the year. Because of these adjustments, Staff observes that the demand charges for the two classes diverge to some degree. Staff notes that AIU relies on the Commission's Orders in its prior rate cases to justify combining elements of the DS-3 and DS-4 rate classes. (See Docket Nos. 07-0585 et al. (Cons.), Order at 362-63) A central tenet of AIU's analysis supporting its ratemaking approach for the two classes is the assumption that conceptually, it costs about the same to provide a kW of service to a DS-3 customers as it does a DS-4 customer. AIU's analysis, Staff continues, finds that the $/kW charges for the DS-3 and DS-4 rate classes should be close together.

Staff maintains that AIU's proposal to collectively design rates for the DS-3 and DS-4 classes conflicts with basic principles of utility ratemaking and should be rejected. Because its alternative approach designs rates for the two classes based on each class' costs of service, Staff contends that its way is more reasonable and should be adopted in this case. Staff argues that the problem with AIU's analysis lies with the assumption that it costs about the same to provide a kW of service to DS-3 and DS-4 customers. Staff contends that that is not necessarily the case because a customer's impact on the distribution system depends not just on the level of his or her demand, but also on when that demand takes place. Staff asserts that that is particularly true for facilities such as distribution lines and substations which may be constructed to meet the collective peak demands of many customers from different rate classes. The impact of any individual customer's demand on the cost of a distribution line or substation depends on how his or her demand coincides with the peak demand for that equipment. If one customer peaks when other customers use less, Staff observes that that customer may have minimal impact on the cost of a distribution line or substation. If another customer's peak demands coincide with the collective peak demands for this equipment, Staff relates that the utility may find it necessary to invest in more capacity. Therefore, because not all electricity demands are the same from the standpoint of distribution costs, Staff asserts that there is no reason to assume that unit demand costs for DS-3 and DS-4 customers will be comparable. Staff points out that AIU witness Jones even acknowledges that "one class may have a greater contribution to the peak demand than another, thus yielding different costs per kW." (Ameren Ex. 40.0 Second Revised at 8)

As alluded to above, Staff also complains that AIU's combined ratemaking approach for the DS-3 and DS-4 classes conflicts with general ratemaking principles which first allocate costs to individual rate classes and then design rates to recover those costs from individual ratepayers. Customers are placed into different rate classes because their usage characteristics are assumed to have a differing effect on system costs. Staff contends that AIU's combined approach does not fully recognize these cost differences and instead essentially treats the DS-3 and DS-4 classes as a single class for ratemaking purposes with some adjustments thrown in to reflect some differences between the two classes. Staff believes that AIU's proposal would send inaccurate price signals to DS-3 and DS-4 customers about their relative cost of delivery services. Specifically, it would understate the cost of delivery service for DS-3 customers and overstate the cost for DS-4 customers. Staff states that this would signal customers in the two classes to use either too much or too little electricity, resulting in an inefficient level of use.

Staff complains further that the assumed commonality between DS-3 and DS-4 customers for rate design inappropriately lumps together customers that are much different in size. Customers in the DS-3 class have demands ranging from 150 kV up to 1 MW while DS-4 class demands range higher. A common rate design for the two classes would lump together 150 kW customers with customers 10 MW or larger. The cost of serving these two customers can be considerably different simply because of their relative demand sizes without considering their respective load shapes.

In response to Staff's concerns about size differences among customers, AIU asserts that its rate design method carefully groups customers by voltage level such that customers' demands supplied from Primary Voltage are grouped together, as are those from High Voltage and +100 kV groupings. Staff contends that this argument is undermined by the fact that DS-3 and DS-4 customers face the same set of customer charges with differences based solely on voltage levels under AIU's proposal. As an example, Staff states that a 500 kW DS-3 customer could pay a higher customer charge than a 5 MW DS-4 customer if the former was served at a higher voltage level. The fact that the DS-4 customer's demand is ten times as high as for the DS-3 customer would play no role in determining their relative customer charge levels. Staff maintains that this is an unreasonable assumption on AIU's part.

Staff notes as well that AIU's cost of service and rate design approaches for the DS-3 and DS-4 classes are fundamentally inconsistent. Staff explains that AIU considers the classes different from a cost of service standpoint, but then lumps them together for the purpose of designing rates. Evidently, AIU believes there are sufficient cost differences between the two groups of customers to justify putting them into two separate classes for allocating the cost of service. Staff points out, however, that AIU then fails to recognize those differences in cost when it comes to rate design. Staff asserts that it is illogical to allocate costs separately to the DS-3 and DS-4 classes and then implement a collective rate design that tries to paper over the cost differences between the two.

Staff presents an alternative which designs rates separately for the two classes based on the respective costs and billing determinants for each class. Staff maintains that designing rates for the DS-3 and DS-4 classes separately promotes equity by ensuring that customers in each class pay rates designed to recover the costs that have been allocated to that class. The alternative approach of collectively designing charges that apply to both the DS-3 and DS-4 classes produces rates for customers in each class that do not necessarily correspond to the level of costs they have been allocated. Staff states that AIU's approach can result in an over-recovery of costs for one class and under-recovery for the other.

c. IIEC Position

Because AIU's approach to determining Distribution Delivery Charges has the effect of combining the DS-3 and DS-4 rate classes for cost allocation purposes, IIEC opposes this rate design approach. IIEC argues that AIU's approach is inconsistent with traditional ratemaking, which first allocates costs to rate classes and then designs rates to recover costs from customers within each class. Costs are generally allocated to classes of customers with similar cost characteristics. IIEC complains that AIU's approach, in contrast, treats the DS-3 and DS-4 classes as a single rate class and obscures the level of costs imposed by members of the classes. Despite AIU's assertions to the contrary, IIEC insists that this rate design approach is not consistent with any past Commission orders. IIEC also criticizes AIU's approach for ignoring the differences in size of DS-3 and DS-4 customers. Similarly, IIEC disagrees with Kroger that delivery voltage is the most accurate indicator of the cost to serve a customer. Thus, IIEC concludes that AIU fails to give consideration to the fact that customers with different demand sizes can impose different costs on the system. Finally, IIEC contends that there is no reason to assume that DS-3 and DS-4 customers have comparable unit demand costs. Under the circumstances, IIEC recommends that AIU's approach to the design of rates for the DS-3 and DS-4 classes in this proceeding be rejected.

d. Kroger Position

While AIU proposes a uniform Customer Charge and Transformation Charge between the DS-3 and DS-4 classes, AIU proposes a Distribution Delivery Charge for the DS-3 class that is notably greater than that proposed for the DS-4 class. Kroger is very troubled by this and believes that it is appropriate for the Distribution Delivery Charge for customers on the DS-3 and DS-4 rate schedules to be approximately equalized. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together in this proceeding.

Table KCH-1 in Kroger Ex. 1.0 sets forth AIU's proposed Distribution Delivery Charges:

Utility Distribution Company Voltage	DS-3 Charge ($/kW)	DS-4 Charge ($/kW)
Ameren CILCO		
Primary Service	5.711	3.016
High Voltage Service	1.643	0.954
+100 kV Service	0.049	0.033
AmerenCIPS		
Primary Service	4.706	3.041
High Voltage Service	2.054	1.375
+100 kV Service	0.098	0.077
AmerenIP		
Primary Service	7.278	5.597
High Voltage Service	2.403	1.771
+100 kV Service	0.162	0.139

As seen in Table KCH-1, AIU's proposed DS-3 Distribution Delivery Charge for Primary Service is 30% greater than the proposed DS-4 counterpart in the AmerenIP territory. In the AmerenCIPS territory this difference is 55%, and in the AmerenCILCO territory, this difference is 89%. Kroger points out that this means that a Primary Service customer in the AmerenCILCO territory with a billing demand of 999 kW under DS-3 would pay a total Distribution Delivery Charge bill that is nearly 90% greater than an otherwise identical customer with a billing demand of 1,001 kW taking service under DS-4.

Kroger observes that although AIU proposes a larger percentage increase for DS-4 than DS-3, the two rates nevertheless would move further apart under AIU's proposal. Kroger recognizes that this statement may appear paradoxical, but insists that it is true. Kroger explains that this is because the Distribution Delivery Charge for the DS-3 class already exceeds that for the DS-4 class, and the proposed increase for the DS-4 class is not sufficient to catch up with the charge for the DS-3 class. Kroger offers an example based in AmerenCIPS' service area. For AmerenCIPS, Kroger states that the proposed overall rate increase for DS-3 is 12.43%, while for DS-4 it is 19.53% (excluding distribution tax). Yet Kroger calculates that the proposed increase for DS-3 is greater than DS-4 for each delivery voltage level, except Transmission Voltage Service. For instance, Kroger notes that the proposed increase for the DS-4-Primary Distribution Delivery Charge is only 5.59%. In contrast, Kroger continues, the proposed increase for the DS-3-Primary Distribution Delivery Charge is 14.47%. Kroger adds that for High Voltage Service, the proposed Distribution Delivery Charge increase for DS-3 exceeds that of DS-4.

Kroger maintains that the widely divergent Distribution Delivery Charges paid by DS-3 and DS-4 customers is not cost-justified. According to Kroger, the most important cost distinction for delivery service is the voltage at which customers take service. Kroger contends that this is a far more important distinction than whether a customer is above or below 1,000 kW of demand which is largely irrelevant insofar as per-kW delivery costs are concerned. Kroger states that AIU even admits that conceptually providing a kW of service to customers at a given voltage level costs the same whether the customer requires 150 kW or 2,000 kW. (See Ameren Ex. 16.0E at 39)

Kroger finds unpersuasive AIU's two arguments attempting to justify the different Distribution Delivery Charges for the DS-3 and DS-4 rate classes. AIU's first argument is that the difference is, at least in part, attributable to the recognition of DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. Kroger does not dispute the existence of the reactive power revenue offset, but contends that it is relatively too small to explain the disparity between the Distribution Delivery Charges for the DS-3 and DS-4 rate classes.

AIU's second argument pertains to the more consistent distribution of billing demand during the course of the year displayed by DS-4 customers relative to DS-3 customers. AIU asserts that this pattern of usage justifies a reduced unit demand charge for DS-4 relative to DS-3. While Kroger agrees that, mathematically, a customer whose billing demand is relatively constant throughout the year will produce more revenue than a customer with the identical annual peak demand, but who exhibits more variable billing demands throughout the course of the year, it does not necessarily follow that the demand charge for a class with more constant average usage should be lower than that of a class with more variable usage. To the extent that a class has more variable usage, Kroger contends that this fact is already captured in the billing determinant used to calculate the demand charge. Kroger insists that there is no need to make a further adjustment to account for it (as AIU does in Ameren Ex. 16.11E). Moreover, Kroger asserts that a class with more variable usage (e.g., DS-3) is likely to have greater demand diversity at the time the class NCP is measured, all other things being equal. As individual customers are billed for demand based on their individual peaks (which may not occur at the time of the class NCP), Kroger states that a class that exhibits variable demand patterns may very well warrant a lower demand charge relative to a class that exhibits a more constant demand pattern (but has less diversity at the time of the class NCP). Unless both diversity factors are taken account of (i.e., diversity of billing demand throughout the year and diversity of class demand at the time of class NCP), Kroger states that one can not conclude that a given group of customers warrants a lower demand charge relative to another group based on considering one aspect of diversity in isolation. For these reasons, Kroger contends that AIU's second rationale for a difference in DS-3 and DS-4 demand charges is not persuasive.

Kroger observes that despite offering these two reasons to explain the difference in the Distribution Delivery Charges for the DS-3 and DS-4 rate classes, AIU also concedes that its two reasons can not explain all of the difference. According to Kroger, AIU suggests that imperfections in prior COSS may be responsible, at least in part. (See Ameren Ex. 16.1E at 7) AIU witness Jones, Kroger continues, also indicates agreement that DS-3 rates are too high relative to DS-4 rates. (See Ameren Ex. 40.0 Second Revised at 21) Kroger maintains that these statements by AIU as well as AIU's failure to remedy the problem on its own warrant action in this docket moving the DS-3 and DS-4 Distribution Delivery Charges closer together.

In response to Staff's concerns about the impact of load diversity on the cost of serving DS-3 and DS-4 customers, Kroger agrees that load diversity is a key determinant of distribution demand costs. Kroger points out, however, that the question at hand is how that diversity is best captured for the purpose of setting class rates. Rates are not set one individual at a time. Instead, the benefit of the diversity of an aggregation of customers is shared across the group. Kroger's concern is identifying the most appropriate grouping of customers.

Kroger also disagrees with Staff's opinion that customer size matters more than voltage level. For delivery services, Kroger contends that it is voltage that matters most. Kroger argues that there is no evidence presented in this case that the size of individual customer demands for DS-3 and DS-4 customers impacts the unit-cost-of-service for distribution demand. To the contrary, Kroger observes, AIU's COSS shows that DS-3 and DS-4 rates should be converging. According to Kroger, even Staff's discussion of distribution cost focuses on the role of load diversity, which is an entirely separate matter from customer size.

To address its concerns, Kroger suggests that the Distribution Delivery Charges for the DS-3 and DS-4 classes be converged for customers taking service at the same voltage within a given service territory, except for a minor difference to recognize DS-4 reactive power revenues as an offset to the DS-4 Distribution Delivery Charge. To reach this objective, Kroger recommends that the Commission initiate steps to move these rate schedules closer together over time. Specifically, in the current proceeding, Kroger recommends that this first step be implemented by removing 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges, with an adjustment to recognize DS-4 reactive power revenues. To the extent that the final approved revenue requirement is reduced, then the results for both rate schedules should be adjusted downward while retaining the targeted rate differential. The impact of adopting Kroger's proposal to remove 50% of the differential between the DS-3 and DS-4 Distribution Delivery Charges is presented in Kroger Ex. 1.4, using the combined DS-3/DS-4 revenue requirement proposed by AIU in this proceeding.

e. Commission Conclusion

The underlying concern with the DS-3 and DS-4 Distribution Delivery Charges is whether these rate classes are sufficiently similar to warrant similar charges. In response to concerns raised by Kroger in prior AIU delivery service rate cases and Commission direction that Kroger's concerns be at least considered, AIU has proposed a rate design for the DS-3 and DS-4 rate classes that it believes will eventually move them closer together. Kroger complains that AIU's proposal does not go far enough and recommends that the Commission go further in this proceeding in closing the gap between the rate classes. Staff and IIEC contend that AIU and Kroger are in error.

At the heart of Kroger's concerns is its position that it does not cost AIU any more to serve a DS-3 customer than a DS-4 customer when both are taking service at the same voltage. Customer demand, in Kroger's opinion, is irrelevant when determining the cost of delivering electricity. Kroger has made this argument in AIU's last two electric delivery service rate cases and in both instances the Commission has indicated that further information was needed before any determination could be made.

Additional information has been provided, but the Commission remains unconvinced that the changes sought by Kroger are warranted. Specifically, the Commission is not persuaded that voltage is the determining factor in cost causation when it comes to delivering electricity. While a factor, voltage is not the sole factor. The Commission continues to believe that customer size/demand plays a role in cost causation as well, as discussed by Staff and IIEC. Even if the Commission agreed with Kroger, it would be hesitant to adopt Kroger's proposal given the absence of any evidence on how it would impact AIU's other customers.

While AIU's class COSS may suggest that moving the DS-3 and DS-4 classes closer together is appropriate, the Commission is not willing to unquestionably rely on those results given the corrections that the Commission has made to AIU's electric COSS. Additionally, the Commission considers separating the DS-3 and DS-4 classes for cost allocation purposes inconsistent with the decision to combine the classes for rate design purposes. Absent compelling evidence that such a rate design is warranted, the Commission declines to adopt AIU's proposal.

The remaining rate design proposal for the DS-3 and DS-4 classes is that of Staff. While not perfect in addressing all of the concerns raised regarding these rate classes, the Commission finds Staff's proposal sufficient for purposes of this proceeding. Accordingly, Staff's proposal on this issue is adopted.

4. DS-5 Fixture and Distribution Delivery Charges

The DS-5 rate class provides customers with dusk-to-dawn, photo-cell controlled lighting service. The distribution charge does not include power and energy, transmission, or delivery service charges, which are separately stated. The distribution charge also does not include the cost of the fixtures, which may or may not be owned by AIU. A monthly Fixture Charge is assessed for street lights that are owned by AIU.

a. LGI Position

LGI pays for street lighting service under AIU's DS-5 rate. LGI claims that in AIU‘s last rate case, the Commission directed AIU to analyze the cost of lighting service in each utility‘s electric service area and develop cost based rates for lighting fixture charges. In this docket, LGI understands that AIU‘s pricing methodology is designed to move Fixture Charges for comparable lights for the three companies to a uniform level. LGI maintains that it is important that the lighting Fixture Charges be uniform across the companies since it is difficult for customers to understand why it costs twice as much for a streetlight fixture in AmerenIP‘s service area than it does for the same streetlight fixture located in AmerenCIPS‘ service area, especially where the service areas are literally across the street from each other.

With three exceptions, LGI generally supports AIU‘s proposal regarding the DS-5 class in this docket. First, LGI asserts that the DS-5 class continues to subsidize the rates for other delivery service classes. Second, LGI complains that AmerenIP‘s lighting Fixture Charges continue to be significantly higher than the lighting Fixture Charges of AmerenCILCO and AmerenCIPS, without any cost justification. Third, while AIU supports its pricing principles in this case, LGI notes that AIU witness Jones testifies that there may be problems in applying the principle of setting DS-5 rates to achieve equalized class rates of return for each of the three electric systems in future rate cases.

Regarding its third exception, LGI states that Mr. Jones‘ issue arises as a result of the fact that the Fixture Charges for AmerenCIPS are significantly lower than the Fixture Charges for AmerenIP and AmerenCILCO. In fact, AmerenIP‘s Fixture Charge is about twice that of AmerenCIPS. So when the Fixture Charges become uniform among the three utilities, in order to meet the targeted revenue requirement for the DS-5 class and achieve equalized rates of return with the other AmerenCIPS DS classes, LGI asserts that any increases to the Fixture Charges for AmerenCIPS would have to be offset by decreases to the DS-5 Distribution Delivery Charge for AmerenCIPS. In other words, LGI states that it is possible in the future that the increase in Fixture Charges for AmerenCIPS would result in a near zero or negative Distribution Delivery Charge for AmerenCIPS.

LGI does not insist that uniformity be established in this proceeding. As long as AIU commits that it will continue to move DS-5 rates closer to equal rates of return in the next delivery service rate case, LGI will be satisfied until then. LGI wishes to withhold final judgment until having the opportunity to review the details of AIU's analysis in the next delivery service rate case.

b. AIU Position

For the DS-5 rate class, AIU took steps to create more uniformity among the Fixture Charges. AIU does not propose full uniformity at this time because it considers the rate changes to accomplish full uniformity too great. AIU constrained rates so that the change in rates results in a change of about $1 per fixture to the high pressure sodium 100 W fixture price. AIU states that it took those steps in response to LGI's concerns in this case, as well as the previous rate case.

Staff, however, contends that movement to more equal rates does not justify AIU's increased revenue allocation to the DS-5 class. AIU counters that Staff's approach does not provide sufficient weight to the lighting incremental cost study, ignores LGI's pleas that Fixture Charges be brought closer together, and does not adequately address the Commission's inquiries from AIU's prior rate order about moving Fixture Charges closer together. Movement toward uniform Fixture Charges across the three companies, using the incremental cost study as a guide, makes sense according to AIU because of outside vendors compete against its standard fixture offerings. Movement toward uniform Fixture Charges also makes sense, AIU adds, because there is no difference among the three companies in the incremental costs of providing a fixture.

Staff further claims that by not setting each individual company's DS-5 revenue allocation target at the level to achieve an equal return, AIU's method is arbitrary and unfair. In response, AIU asserts that its DS-5 revenue allocation approach is methodical, with the ultimate goal of recovering the cost of service at an equal return from the combined DS-5 classes of the three companies in a future case. The goal at this time, AIU explains, is to make progress toward uniform rates by easing AmerenIP rates lower and AmerenCIPS rates higher. Since each company is a single legal entity, AIU states that any revenue excess or deficiency still needs to remain within the individual utility, and should be absorbed by other rate classes.

Thus, by adopting its approach, AIU contends that the Commission would not be abandoning cost-based ratemaking. To the contrary, AIU argues, it would reflect the recognition that moving toward a uniform pricing approach that uses the incremental cost study as a guide, but ultimately constrained to the total embedded cost of service for all three utilities combined, is a sound policy choice.

c. Staff Position

Staff prefers its own rate design for the DS-5 lighting class over AIU's. Staff states that its approach would revise AIU's proposed lighting rates for each company on an equal percentage basis to conform to Staff's recommended revenue allocations for the lighting classes. Staff contends that its approach will best ensure that lighting customers only pay their fair share of system costs.

AIU argues that Staff's proposed lighting rates are flawed because they are derived from current DS-5 rates and therefore ignore the discussion of bringing Fixture Charges closer together. Staff responds that AIU is incorrect and asserts that the starting point for Staff's proposed DS-5 rates is AIU's proposed rate design which incorporates movement toward more equal charges. Staff adds, however, that such movement must be balanced with an allocation of the revenue requirement that is equitable to all rate classes. Staff asserts that its proposed revenue allocations are fair to all rate classes and its rate design for the lighting class is reasonable as well.

d. Commission Conclusion

The Commission recognizes that AIU is in a difficult situation in which it is working toward uniform lighting rates among the three electric utilities as encouraged by the Commission while at the same time trying to keep in mind the cost of service. At the outset, the Commission needs to clarify that it does not necessarily expect Fixture Charges to someday be identical across the three electric utilities. The directive that the Commission gave AIU in its last rate proceeding for its next (this) rate proceeding is "to address the possibility of moving the light fixture charges toward a more similar charge among AmerenCILCO, AmerenCIPS, and AmerenIP." (Docket Nos. 07-0585 et al (Cons.), Order at 359) The Commission does not want to give AIU the impression that it expects AIU to "force" identical Fixture Charges into the DS-5 tariffs even if legitimate cost of service reasons warrant different treatment. The direction given to AIU in its last rate proceeding is consistent with this message.

That being said, it appears to the Commission that AIU earnestly attempted to comply with the Commission's directive in the last rate proceeding. By considering both the results of its incremental COSS and embedded COSS, AIU appears to be trying to move the Fixture Charges closer to together while bearing cost of service in mind. The Commission recognizes that the numbers are apt to change after AIU reruns the COSS, but nevertheless finds the methodology reasonable for the DS-5 class for purposes of this proceeding. In contrast, it is not clear to the Commission how Staff's approach is designed to move the Fixture Charges closer. Accordingly, the Commission accepts AIU's position on this issue for purposes of this proceeding.

5. Combined Billing of Multiple Meters

a. IIEC Position

IIEC proposes a modification to AIU's Standards and Qualifications for Electric Service, so that combined billing of multiple meters, on the same or adjacent premises, would be permitted. Currently, the combined billing of multiple meters on the same or adjacent premises is not permitted, except for those customers having agreements with

AIU or having the benefit of tariff provisions permitting same prior to January 2, 2007. AmerenIP previously permitted such combined billing.

IIEC asserts that AIU's current policy has several adverse implications for larger customers. Among the implications, IIEC asserts, is the fact that it creates more customer accounts than are necessary and increases AIU‘s customer charge revenue. IIEC adds that it reduces the beneficial impact of diversity in separately metered loads of a single customer in a single location on the Distribution Delivery Charge. The current tariff provisions, IIEC continues, also effectively create a barrier to the development of combined heat and power (—CHP”) installations under certain circumstances.

With regard CHP installations, IIEC explains that industrial customers with a number of processes under one account proposing to construct a CHP or cogeneration plant on an adjacent site would be required to treat the CHP plant as a separate account from the remainder of the customer‘s load served by the CHP facility. According to IIEC, such a customer would not be able to enjoy the benefit of using the output of its CHP plant to reduce the amount of electricity delivered to other production facilities in the same plant, but on adjacent premises. IIEC further asserts that to the extent the power generated by the CHP unit is cheaper than power available in the market, the owner would not be able to replace the more expensive power with the cheaper CHP unit power at its adjacent facilities. IIEC also contends that AIU‘s policy becomes a barrier to CHP development if AIU begins collecting the PURA tax through a cent per kWh charge. Under such circumstances, the customer would pay the full PURA tax on all of the separate accounts at its plant without offset for the power generated by the CHP plant. If the generator output is not included within the same account as the plant load, IIEC complains that the customer would pay the PURA tax on the full plant load even though the net effect of the new generator is to reduce the amount of energy the utility needs to deliver to the customer for its entire manufacturing plant or possibly to the utility system as a whole.

While IIEC acknowledges that CHP units have still been developed in AIU's service territory, IIEC argues that that fact does not address the fundamental problem with AIU‘s policy, which discourages CHP units on a going-forward basis. IIEC also maintains that spending significant sums to reconfigure electrical distribution systems to accommodate a new CHP plant is not a satisfactory solution to the problem. Customers of this kind, IIEC contends, should not be forced to expend large sums of capital on reconfiguring electrical distribution systems in order to provide a source of power and energy that is a preferred source of power and energy for Illinois, when a simple change to AIU‘s tariffs will accommodate the construction of the CHP unit without such expenditures. IIEC references Section 16-115D(h) of the Act in support of its assertion that Illinois law encourages CHP installations.

IIEC finds little reassurance in AIU's statement that its tariffs allow 40 kW and over cogenerators to reduce their Distribution Delivery Charge through net metering. IIEC points out that under Section 16-107.5 of the Act, net metering is not available to generating units with a rated capacity greater than 2,000 kW. IIEC asserts that eligible units are relatively small, and would be hardly comparable to the CHP or other cogeneration units that may be built by a large manufacturing customer to serve the load at its manufacturing facility, which may be much larger than 2,000 kW of electrical demand. Furthermore, IIEC points out that AIU has also apparently overlooked the provisions of the net metering legislation which limits the applicability of the law to retail customers owning or operating a ―solar, wind or other renewable electrical generating facility." (220 ILCS 5/16-107.5(b)) The Act further defines ―renewable generating facility" to mean a facility powered by ―solar electric energy, wind, dedicated crop for energy generation, anaerobic digestion of livestock or food processing waste, fuel cells or micro turbines powered by renewable fuels, or hydroelectric energies." (Id.) IIEC asserts that a large cogenerating unit at a steel manufacturing facility, for example, fueled by something like coke oven gas or fuels other than those mentioned, would not benefit from AIU's net metering tariffs.

To the extent that a customer seeks other benefits associated with distributed generation, AIU notes that Rider QF provides two different compensation options that provide the customer with a fair market value for the output of its generating unit. IIEC observes, however, that this applies only to the energy value of the generating unit, and does not address the recovery of delivery service costs generally, or the PURA tax specifically from these customers, without giving them credit for their cogeneration.

In response to AIU's billing determinants argument, IIEC asserts that AIU fails to recognize that if the CHP facility were simply located on the customer's premises, behind the meter, the reduction in billing demands would be the same whether the CHP unit was located on or adjacent to the customer's premises. IIEC states that locating a CHP facility on an adjacent property rather than on its main plant property may be due to circumstances largely beyond the customer's control (e.g., a bisecting roadway), and it should not be penalized simply due to such circumstances.

Lastly, AIU argues that IIEC has not proposed any specific tariff language to be reviewed by the Commission. IIEC points out that its recommendation is that AIU be required to change its policy. Presumably, if the Commission follows IIEC's recommendation, AIU would present the tariff language necessary to accomplish that change in policy. IIEC also notes that until recently, AmerenIP had provisions in its Standard Terms and Conditions which addressed IIEC's concerns. IIEC does not believe it would be difficult for AIU to develop, or simply modify and reuse, the prior language to achieve the change in policy directed by the Commission.

b. AIU Position

In response to IIEC's concerns, AIU recognizes that the existence of more than one service point results in a corresponding increase in the number of Customer Charges assessed on the customer. What IIEC fails to consider, AIU counters, is that for customers metered at primary voltage or greater, a substantial portion of the cost basis for the Customer Charge is for the current and/or potential transformers used to meter the customer. Since metering has been unbundled, the Commission has directed that current and potential transformers associated with metering remain part of the utility's responsibility. AIU states that customers are assessed a monthly Customer Charge in lieu of a lump sum payment predominantly to pay for the current and/or potential metering facilities. According to AIU, the added revenue offsets the added cost.

AIU also agrees with IIEC that its policy may diminish a possible reduction in the Distribution Delivery Charge for the customer if it was allowed to combine all service points for billing purposes. AIU asserts, however, that IIEC fails to recognize that AIU's tariffs already provide generators with the ability to mitigate their Distribution Delivery Charges. AIU explains that under Section 16-107.5 of the Act, non-residential customers with generators with a name plate capacity rating in excess of 40 kW are assessed delivery service charges based on a ―gross" method, where the amount of generation is not allowed to serve as an offset to delivery service charges. Those customers operating on-site generators with capacities under 40 kW are allowed to offset distribution charges. Under Rider QF, however, a customer with a CHP facility with output that exceeds the load at a service point for the entire month would avoid Distribution Delivery Charges, even though facilities were designed and built to ensure adequate distribution capacity is available to serve the customer in the event their generation facility became unavailable for any period of time. AIU states that this practice has been in place for several years, and pre-dates the establishment of net-metering in Illinois.

Essentially, AIU continues, the energy and demand associated with load are registered by the meter, in a manner inclusive only to the extent required beyond what is provided by the generator. AIU allows all customers with facilities up to 1 megawatt to avail themselves of this benefit pursuant to longstanding tariff policies. Beyond that point, AIU requires that generation be separately metered. Further, AIU states that the customer must interconnect the generator directly to the system, or else they can not receive the load off-setting benefits of the Rider QF option, described above. Customers that choose to have AIU run a separate distribution line to the facility will be required to have the interconnected facilities metered after installation of the load-serving line segment.

Additionally, to the extent a customer is metered at the generator, and assessed a delivery service change for all customer load, AIU notes that under the current Rider QF, the customer may choose to be compensated under a fixed or variable rate. AIU states that such compensation will provide some level of total bill offset, even providing compensation in excess of supply charges assessed in certain circumstances. Thus, between net metering and its established policy for onsite generation for Rider QF customers, AIU believes that it allows for significant flexibility for large customers pursuing on site generation supply options. AIU asserts that any expansion of these options to include additional aggregation of metering data for billing purposes is not cost-based, and ultimately would increase the cost responsibility borne by other customers.

Moreover, AIU states that Section 16-107.5 provides that non-residential customers taking service under a net-metering election at a level greater than 40 kW are required to pay distribution charges and taxes for their delivered power. AIU maintains that the policy implications of this legislative prerogative would bode against the revision of Rider QF policies in a manner that would further reduce delivery service and other charges, such as taxes and energy efficiency rider revenues.

With regard to IIEC's concerns over CHP installations, AIU reiterates that current tariff provisions allow customers a reasonable opportunity to achieve the same end that IIEC advocates. For customers that do not qualify, or elect to receive service pursuant to Rider NM - Net Metering Service, Rider QF provides two compensation options for customers that produce more power than they use: fixed-price and variable-price compensation. AIU states that both compensation methods reflect a fair market value for the qualifying facility output. AIU adds that customers that are unhappy with the Rider QF options may take their power output directly to MISO and register their generator as a resource. In AIU's view, customers have both physical and financial options that allow them to effectively reduce their electricity costs using their CHP facility.

From a broader policy perspective, AIU notes that its tariff provisions related to metering and cogeneration are tailored to comply with applicable laws and regulations, as well to avoid unnecessary subsidization from other customer classes. AIU believes that removing any undue barriers to supply options, including self-supply by means of distributed generation, is a goal worthy of consideration. AIU states that its current policy, however, of allowing one meter per service point more closely aligns distribution service cost recovery with those who cause the cost. Measurement of energy on a per service point basis, AIU continues, is a foundational step to associating energy consumption costs with the facilities and customer behind the delivery point.

Finally, AIU states that its billing determinants have not been reviewed in order to determine the impact of implementing IIEC's proposal. AIU points out that there is at least one large CHP facility which recently began operating in AmerenIP's service area. A change to the metering policy would effectively reduce the billing demands shown in the test year billing determinants, and thus reduce AmerenIP's expected revenue. AIU adds that the prices to other customers would need to be increased to recover the authorized revenue requirement. Because no party has performed such analysis, AIU maintains that IIEC's recommendation should be rejected. Additionally, AIU indicates that any new tariff language would need to be developed and reviewed in the same way that other tariff changes were reviewed in this case. Since the IIEC has not proposed any such tariff language for review by parties in this docket, AIU states that there is nothing for the Commission to review.

c. Commission Conclusion

Having considered the record, the Commission finds merit in IIEC's position. Despite AIU's arguments to the contrary, the Commission is persuaded that combined billing of multiple meters, on the same or adjacent premises, should be permitted. AmerenIP apparently even allowed combined billing until relatively recently. AIU's reliance on Section 16-107.5 of the Act is misplaced, as it is not even applicable to the situation at hand. Similarly, Rider QF, while applicable to CHP and other cogeneration facilities, is not relevant to the question of combined billing.

To the extent that the current tariff provisions impede the development of industrial cogeneration projects, the Commission views the elimination of such hindrances as a side effect of permitting combined billing. If the practicality of combined billing also facilitates cogeneration projects that are consistent with Illinois policy, the Commission considers that outcome fortuitous and encourages customers to take advantage of such opportunities.

While the Commission finds that combined billing is appropriate, the Commission is hesitant to direct AIU to prepare tariffs allowing such as part of its compliance tariff filing at the conclusion of this proceeding. Determining language implementing combined billing may not be as straightforward as IIEC suggests. Therefore, to avoid any complications associated with AIU's final tariffs as well as any unforeseen rate or rate design problems, the Commission refrains from directing AIU to implement combined billing in this proceeding. Instead the Commission directs AIU to work with IIEC, Staff, and any other interested parties to develop tariffs addressing the concerns of those involved. Whether tariffs permitting combined billing of multiple meters, on the same or adjacent premises, can be agreed upon or not, AIU should include such tariff provisions with its next electric rate case filings. If the tariff language is not agreed upon, interested parties are free to litigate the issues. Those objecting to AIU's language, however, should submit alternative language for the Commission's consideration.

6. Rate Limiter

Both the DS-3 and DS-4 rate classes currently contain rate limiter provisions that ensure the monthly charges for the sum of Distribution Delivery and Transformation Charges are limited to no more than a set ¢/kWh value if 20% or less of the customer's annual usage occurs in the summer months of June through September. The limiter value is presently 1.953 ¢/kWh for AmerenCILCO, 2.223 ¢/kWh for AmerenCIPS, and 2.613¢/kWh for AmerenIP. The limiter values do not differ between the DS-3 and DS-4 rate classes. The rate limiter provisions were implemented through the Order in Docket No. 07-0165. At that same time, DS-3 and DS-4 Distribution Delivery Charges were increased to maintain revenue neutrality.

a. GFA Position

AIU proposes to constrain the increase in delivery service rates to 23.5% for AmerenCILCO, 19.5% for AmerenCIPS, and 21.8% for AmerenIP. GFA complains, however, that AIU has proposed higher increases to the rate limiters than are proposed for the respective rate classes. GFA argues that AIU's proposal in this proceeding disproportionately impacts grain companies. According to GFA, at least one grain company will experience a delivery service rate increase as high as 42%. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes. GFA contends that this approach more closely tracks the approach taken by the Commission in AIU's previous rate proceeding, Docket Nos. 07-0585 et al (Cons.), where the Commission approved an across-the-board increase to the rate limiters, thereby treating the rate limiter customers the same as other customers.

GFA acknowledges that both the Commission and AIU have recognized the need to reduce and eliminate the rate limiters at the appropriate time, but maintains that now is not the time. GFA contends that the time to consider eliminating the rate limiters is when AIU files a rate case based on a class COSS, and proposes a fully cost-based rate design. While AIU filed a class COSS in this proceeding, GFA states that AIU deviated from it in designing its proposed rates. GFA adds that various parties have advocated differing allocators in this case as well (e.g. CP vs. NCP). Until the Commission has reviewed and determined the appropriate allocators to be used in a full class COSS rate case, with due consideration of seasonal rates, GFA asserts that it will not be known whether and to what extent rates are fully cost justified. Without that knowledge, GFA contends that the Commission will not know in which direction and to what degree rates should be adjusted to eliminate the rate limiters.

b. AIU Position

AIU proposes to retain the rate limiter provision, but increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under proposed rates as it is under present rates. AIU proposes to set the limiter value at 3, 3, and 4¢/kWh for AmerenCILCO, AmerenCIPS and AmerenIP customers, respectively. Upon learning the final revenue requirement, AIU states that it will need to recalculate the rate limiter values as part of developing the final rates in these cases.

GFA, on the other hand, proposes to limit the increase to the ¢/kWh rate limiter at the same level as the class average increase. AIU opposes GFA's proposal and argues that an adjustment to the rate limiter by an amount only equal to the class average increase would not allow for the eventual reduction or elimination of the provision, but instead would further increase the subsidy provided to eligible customers. AIU adds that applying its method for conforming rates to the final revenue requirement by decreasing the DS-3 Distribution Delivery Charges (and holding the other charges as proposed) will place downward pressure on the ¢/kWh rate limiter values, which is a benefit to GFA.

c. Staff Position

Staff supports AIU's approach to the rate limiters in this proceeding. Staff observes that AIU's proposals in this case include constraints on revenue increases for individual rate classes as well as continued efforts to limit adverse impacts for large non-summer users in the DS-3 and DS-4 classes. Staff therefore believes that it would be consistent with these efforts to maintain the rate limiters. Also, consistent with the Commission's past pronouncement that the rate limiters are temporary, Staff notes that AIU's proposal facilitates the future elimination of the rate limiters and placement of the larger customers currently under the rate limiter under the same tariffs that apply to other DS-3 and DS-4 customers.

d. IIEC Position

IIEC does not oppose the continuation of the rate limiters in this case, as it has proposed rate moderation/mitigation measures of its own. IIEC notes, however, the apparent inconsistency between AIU's support for the rate limiters for the benefit of grain drying customers, but apparent lack of concern for other large customers. Without the continuation of the rate limiters, IIEC understands that some of AIU's grain drying customers would experience delivery service rate increases as high as 42%. IIEC states that this must be contrasted with increases in delivery service rates as large as 1,000% for some of AIU's largest customers who do not happen to be grain dryers. IIEC views this disparity as further support for its position that AIU has been trying to shift costs away from smaller customers for public relations and political reasons.

e. Commission Conclusion

All of the parties agree that now is not the time to eliminate the rate limiters. The only issue in dispute is how to modify the existing rate limiters to reflect the change in electric delivery service rates. AIU proposes to increase the limiter ¢/kWh amounts to a level so that the total dollar rate limitation effect is approximately the same under the new rates as it is under present rates. GFA recommends that the rate limiters be constrained by the same percentage as the constraints that are applicable to the respective rate classes.

Having considered the arguments, the Commission finds AIU's proposal more in tune with the ultimate goal of eliminating the rate limiters. Specifically, AIU's proposal takes steps toward that goal while GFA's proposal essentially maintains the status quo. While GFA talks about eliminating the rate limiters, its proposal as well as the "conditions" that it believes are necessary before doing so seem geared more toward delaying elimination of the rate limiters. GFA seems to suggest that the Commission must have an undisputed class COSS underlying strictly cost based rates before it can eliminate the rate limiters. Such a scenario would be very rare.

Because it finds AIU's proposal a step toward the goal of someday eliminating the rate limiters, the Commission adopts it for purposes of this proceeding. The

Commission agrees with AIU that upon learning the final revenue requirement, AIU will need to recalculate the rate limiter values as part of developing the final rates in these cases. That is why the Commission is approving AIU's methodology and not the specific ¢/kWh amounts AIU identified in its testimony.

X. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) AmerenCILCO, AmerenCIPS, and AmerenIP are Illinois corporations engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and are public utilities as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendix A attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's electric operations; Appendix B attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' electric operations; Appendix C attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's electric operations; Appendix D attached hereto provides supporting calculations for those portions of this Order concerning AmerenCILCO's gas operations; Appendix E attached hereto provides supporting calculations for those portions of this Order concerning AmerenCIPS' gas operations; and Appendix F attached hereto provides supporting calculations for those portions of this Order concerning AmerenIP's gas operations;

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2008, as adjusted; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, the net original cost rate base for AmerenCILCO‘s electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $275,015,000;

(6) for purposes of this proceeding, the net original cost rate base for AmerenCIPS‘ electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $452,066,000;

(7) for purposes of this proceeding, the net original cost rate base for AmerenIP's electric delivery service operations for the test year ending December 31, 2008, as adjusted, is $1,290,963,000;

(8) for purposes of this proceeding, the net original cost rate base for AmerenCILCO's gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $160,082,000;

(9) for purposes of this proceeding, the net original cost rate base for AmerenCIPS' gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $165,512,000;

(10) for purposes of this proceeding, the net original cost rate base for AmerenIP's gas delivery service operations for the test year ending December 31, 2008, as adjusted, is $435,480,000;

(11) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost electric delivery service rate base is 8.05%; this rate of return incorporates a return on common equity of 9.9%;

(12) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost electric delivery service rate base is 8.02%; this rate of return incorporates a return on common equity of 10.06%;

(13) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost electric delivery service rate base is 8.97%; this rate of return incorporates a return on common equity of 10.26%;

(14) a just and reasonable return which AmerenCILCO should be allowed to earn on its net original cost gas delivery service rate base is 7.83%; this rate of return incorporates a return on common equity of 9.4%;

(15) a just and reasonable return which AmerenCIPS should be allowed to earn on its net original cost gas delivery service rate base is 7.59%; this rate of return incorporates a return on common equity of 9.19%;

(16) a just and reasonable return which AmerenIP should be allowed to earn on its net original cost gas delivery service rate base is 8.59%; this rate of return incorporates a return on common equity of 9.4%;

(17) the rate of return for AmerenCILCO set forth in Finding (11) results in base rate electric delivery service operating revenues of $117,625,000 and net annual operating income of $22,138,000 based on the test year approved herein;

(18) the rate of return for AmerenCIPS set forth in Finding (12) results in base rate electric delivery service operating revenues of $235,899,000 and net annual operating income of $36,255,000 based on the test year approved herein;

(19) the rate of return for AmerenIP set forth in Finding (13) results in base rate electric delivery service operating revenues of $450,412,000 and net annual operating income of $115,798,000 based on the test year approved herein;

(20) the rate of return for AmerenCILCO set forth in Finding (14) results in base rate gas delivery service operating revenues of $65,825,000 and net annual operating income of $12,535,000 based on the test year approved herein;

(21) the rate of return for AmerenCIPS set forth in Finding (15) results in base rate gas delivery service operating revenues of $70,199,000 and net annual operating income of $12,562,000 based on the test year approved herein;

(22) the rate of return for AmerenIP set forth in Finding (16) results in base rate gas delivery service operating revenues of $156,590,000 and net annual operating income of $37,482,000 based on the test year approved herein;

(23) the electric delivery service rates AmerenCILCO, AmerenCIPS, and AmerenIP which are presently in effect are insufficient to generate the operating income necessary to permit each company the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(24) the gas delivery service rates of AmerenCILCO, AmerenCIPS, and AmerenIP which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base: these rates should be permanently canceled and annulled;

(25) the specific rates proposed by AmerenCILCO, AmerenCIPS, and AmerenIP in its respective initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates of each company should be permanently canceled and annulled consistent with the findings herein;

(26) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of

$117,625,000, which represents an increase of $1,416,000 or 1.22%; such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (11) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(27) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $235,899,000, which represents an increase of $16,611,000 or 7.75%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (12) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(28) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate electric delivery service revenues of $450,412,000, which represents an increase of $13,535,000 or 3.1%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (13) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(29) AmerenCILCO should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $65,825,000, which represents a decrease of $9,253,000 or 12.32%; such revenues, in addition to other tariffed revenues, will provide AmerenCILCO with an opportunity to earn the rate of return set forth in Finding (14) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCILCO;

(30) AmerenCIPS should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $70,199,000, which represents a decrease of $2,976,000 or 4.07%; such revenues, in addition to other tariffed revenues, will provide AmerenCIPS with an opportunity to earn the rate of return set forth in Finding (15) above; based on the record in this proceeding, this return is fair and reasonable for AmerenCIPS;

(31) AmerenIP should be authorized to place into effect tariff sheets designed to produce annual base rate gas delivery service revenues of $156,590,000, which represents a decrease of $14,601,000 or 8.53%; such revenues, in addition to other tariffed revenues, will provide AmerenIP with an opportunity to earn the rate of return set forth in Finding (16) above; based on the record in this proceeding, this return is fair and reasonable for AmerenIP;

(32) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AmerenCILCO, AmerenCIPS, and AmerenIP should incorporate the rates and rate design set forth and referred to herein;

(33) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended; and

(34) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for electric delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in electric delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on June 5, 2009 are permanently canceled and annulled.

IT IS FURTHER ORDERED that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP on June 5, 2009, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (26), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (27), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (28), (32), and (33) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Light Company d/b/a AmerenCILCO is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (29), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Central Illinois Public Service Company d/b/a AmerenCIPS is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (30), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Illinois Power Company d/b/a AmerenIP is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (31), (32), and (33) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 29th day of April, 2010.

(SIGNED) MANUEL FLORES

Acting Chairman

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company	**:**	
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<u>ORDER</u>

DATED: December 5, 2012

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ORDER

By the Commission:

I. INTRODUCTION

On April 20, 2012, Ameren Illinois Company d/b/a Ameren Illinois ("AIC") filed with the Illinois Commerce Commission (“Commission”) a verified petition under Section 16-108.5(d) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq., requesting approval of the first update to its Modernization Action Plan-Pricing tariff ("Rate MAP-P"). AIC's Rate MAP-P and corresponding changes to other tariffs were approved in Docket No. 12-0001 on September 19, 2012. The pending filing sets forth AIC's updated cost inputs to Rate MAP-P based on AIC's 2011 Federal Energy Regulatory Commission ("FERC") Form 1.

AIC posted a notice of the filing of the proposed rate changes in its Peoria business office and published a notice twice in newspapers of general circulation within each of its rate zones, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, “Notice Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services.”

On May 23, 2012, the Administrative Law Judges sent AIC a list of deficiencies in its filing in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). AIC responded to the deficiency letter on June 20, 2012.

Petitions seeking leave to intervene were filed by the Citizens Utility Board (“CUB”) and AARP. Both petitions to intervene were granted. The Office of the Attorney General entered an appearance on behalf of the People of State of Illinois. Commission Staff ("Staff") participated as well.

Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on May 16 and September 10, 2012. Thereafter, evidentiary hearings were held

September 12, 13, and 14, 2012. Appearances were entered by counsel on behalf of AIC, Staff, the AG, CUB, and AARP.

At the evidentiary hearings, AIC called 14 witnesses to testify. The 14 witnesses include (1) Michael Getz, AIC's Controller, (2) David Heintz, a Vice President of the consulting firm Concentric Energy Advisors, Inc. ("Concentric"), (3) Leonard Jones, AIC's Manager of Rates and Analysis, (4) Geralynn Lord, the Director of Identity and Customer Education for Ameren Services Company ("AMS")[1], (5) Ryan Martin, Assistant Treasurer and Manager of Corporate Finance for AMS and Assistant Treasurer for AIC, (6) Robert Mill, AIC's Director of Regulatory Policy and Rates, (7) Craig Nelson, AIC's Senior Vice President of Regulatory Affairs and Financial Services, (8) Stan Ogden, AIC's Vice President of Customer Service and Metering Operations, (9) Kathleen Pagel, a Supervisor of Communications within AIC, (10) Ronald Pate, AIC's Vice President of Operations and Technical Services, (11) Ryan Schonhoff, a Regulatory Consultant within AIC, (12) Ronald Stafford, AIC's Manager of Regulatory Accounting, (13) Scott Verbest, Executive Compensation Lead for AMS, and (14) James Warren, a tax attorney with the law firm of Miller & Chevalier Chartered.

Six witnesses testified on behalf of Staff. The Staff witnesses include (1) Karen Chang, (2) Mary Everson, (3) Theresa Ebrey, and (4) Daniel Kahle, Accountants in the Accounting Department of the Financial Analysis Division of the Commission's Bureau of Public Utilities, (5) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, and (6) William Johnson, an Economic Analyst in the Rate Department of the Financial Analysis Division.

CUB offered Ralph Smith, a certified public accountant and senior regulatory utility consultant with the consulting firm Larkin & Associates, PLLC. Michael Brosch, a principal with Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work, and David Effron, a consultant specializing in utility regulation, testified on behalf of the AG and AARP.

AIC, Staff, and CUB each filed an Initial Brief and Reply Brief. The AG and AARP jointly filed an Initial Brief and Reply Brief. A Proposed Order was served on the parties. AIC and Staff each filed a Brief on Exceptions. The AG and AARP jointly filed a Brief on Exceptions. The short statutory deadline did not permit time for filing Briefs in Reply to Exceptions. The Briefs on Exceptions have been considered in the preparation of this Order.

II. NATURE OF AIC'S OPERATIONS

Ameren Corporation ("Ameren") formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIC covers roughly the lower two-thirds of Illinois.

[1] AMS is the service company subsidiary of Ameren Corporation and provides various services to its affiliates, including AIC.

AIC currently serves approximately 1.2 million electric customers and 840,000 natural gas customers. All of AIC's operations are within Illinois, although an affiliate of AIC (Ameren Missouri Company ("AMC") f/k/a Union Electric Company d/b/a AmerenUE ("UE")) provides utility service in Missouri. At one time, AMC's predecessor company served the St. Louis Metro East area in Illinois. That area was later subsumed within the service area of AmerenCIPS. Other affiliates of AIC provide unregulated services. Effective October 1, 2010, AmerenCILCO and AmerenIP merged with and into AmerenCIPS, resulting in AmerenCIPS being the sole surviving legal entity. Simultaneously, AmerenCIPS' name was changed to Ameren Illinois Company d/b/a Ameren Illinois. AIC identifies the former service areas of AmerenCIPS, AmerenCILCO, and AmerenIP as Rate Zone 1, Rate Zone 2, and Rate Zone 3, respectively.

III. OVERVIEW OF 16-108.5 RATE PROCESS

The revisions to the Act made by Public Acts 97-0616 and 97-0646 provide that an electric utility that commits to undertake an infrastructure investment program pursuant to Section 16-108.5(b) may elect to recover its delivery services costs through a performance based rate approved by the Commission. The performance based rate tariff (for AIC, Rate MAP-P) sets forth a formula for calculating a delivery service revenue requirement that will be used to set delivery service charges for retail electric customers. The formula includes the specific cost components that form the basis of the rates charged to the utility's delivery service customer classes. The performance based rate provides for recovery of a utility's actual, prudently incurred and reasonable costs of electric delivery services, except for those costs that the utility continues to recover through automatic adjustment clause tariffs. The performance based rate also reflects the utility's actual capital structure for the applicable year (excluding goodwill) and includes a cost of equity, the calculation of which is addressed in Section 16-108.5. The performance based rate is intended to operate in a standardized and transparent manner and be updated annually to reflect (i) historical data from the most recently filed FERC Form 1, plus projected plant additions and correspondingly updated depreciation reserve and depreciation expense for the year of filing, (ii) a reconciliation of the revenue requirement reflected in rates for each year, with what the revenue requirement would have been had the actual cost information for the year been available at the filing date, and (iii) any adjustments, including adjustments to reflect an earned rate of return on common equity outside the statutory range, required by Section 16-108.5(c). The rates established under this framework are "performance-based" because the ability to use this rate mechanism is dependent on the utility achieving certain metrics and performance goals for the periods they are in effect. AIC's most recently filed FERC Form 1 data from 2011 provides the basis for the pending formula update for Rate MAP-P. The pending updated rates under Rate MAP-P will go into effect January 1, 2013. As a distributor of electricity and natural gas, AIC is a "combination utility" under the revisions to the Act. As such, pursuant to Section 16-108.5(b)(2) of the Act, AIC is to invest $625,000,000 over a ten-year period in electric system upgrades, modernization projects, training facilities, and other smart grid upgrades.

IV. AIC'S PROPOSED REVENUE REQUIREMENT

In Docket No. 12-0001, the Commission approved a revenue requirement of $810,617,000. Upon factoring in the $832,549,000 revenue requirement that AIC seeks in this docket, AIC's proposed update to its formula rate delivery service revenue requirement results in an overall increase of $21,932,000 from the electric revenue requirement ordered by the Commission in Docket No. 12-0001. AIC's calculations use a rate of return of 8.86%.

V. RATE BASE

A. Uncontested or Resolved Issues

1. Gross Plant In Service

AIC notes it has included $5,116,801,000 total plant in service after projected plant additions in rate base. It appears that this amount is not contested. The Commission will adopt this amount for gross plant in service for this proceeding as reasonable.

2. Accumulated Depreciation

AIC has proposed an adjustment to accumulated depreciation which, after projected plant additions, reduces rate base by $2,416,999,000. It appears from the evidence that this amount is not contested; therefore the Commission will adopt this adjustment for the purposes of this proceeding.

3. Cash Working Capital

a. Employee Benefits Expense Lead Days

In direct testimony, Staff proposed using 15.97 expense lead days for employee benefits in the lead/lag study. AG/AARP witness Brosch made the same proposal. AIC indicates that it has accepted this proposal, and no other party has contested this issue. The Commission finds the proposed employee benefits expense lead days to be reasonable, and it will be adopted for purposes of this proceeding.

b. Base Payroll and Withholdings Lead Days

It appears from direct testimony that Staff proposed using 13.12 expense lead days for base payroll and withholdings in the lead/lag study, while AIC proposed using 11.84 expense lead days, which it suggested is based on 2011 data. Staff later agreed to the use of AIC’s suggested lead days for this issue. It appears to the Commission that no other party to this proceeding contested this issue. The Commission finds AIC’s proposal on this issue to be reasonable, and it will be accepted for the purposes of this proceeding.

4. Materials and Supplies

In direct testimony, Staff proposed using a 13-month average balance for the amount of Materials and Supplies included in AIC's rate base for ratemaking purposes, which was accepted by AIC. As no other party contested this issue, the Commission finds Staff's proposal to be reasonable, and it will be adopted for use in this proceeding.

5. Accumulated Deferred Income Taxes – Investment Tax Credits

Consistent with its conclusion in AIC Docket No. 12-0001, Staff proposes that the Commission adopt Staff's recommendation for treatment of the deferred tax asset associated with the unamortized investment tax credit ("ITC"). Staff proposes an adjustment to remove the deferred tax asset associated with the ITC from the balance of accumulated deferred income taxes ("ADIT") that reduces rate base. Staff suggests that the deferred tax asset arises from the deferred credit balance of ITC that represents realized tax savings that have not yet been reflected in AIC's income statement. Since the deferred credit balance of ITC is not deducted from AIC's rate base, Staff asserts that the directly related deferred tax debit balance should also not be included in rate base as a reduction to the ADIT balance. Both AG/AARP and CUB support this same adjustment. AIC has since indicated that it is no longer contesting this issue.

The Commission notes that this issue no longer appears to be contested following the Commission's decision in Docket No. 12-0001, and finds that the proposed treatment of this issue is consistent with the Commission's decision in that docket. The Commission will therefore find that the proposed treatment of ADIT-ITC's is reasonable, and it will be adopted for the purposes of this proceeding.

6. Construction Work in Progress Not Subject to Allowance for Funds Used During Construction

Consistent with its conclusion in Docket No. 12-0001, Staff recommends the Commission adopt Staff's recommendation to reduce construction work in progress ("CWIP") by the amount of accounts payable outstanding at December 31, 2011. (Docket No. 12-0001, September 19, 2012 Order at 72-73) Staff further recommends that since there is one project remaining in CWIP at year-end that was funded by the vendors rather than the shareholders the CWIP balance for that project should be reduced by the commensurate amount of vendor-financing or accounts payable. Staff notes the rates to be established in this case are based on year-end balances and at December 31, 2011, $37,000 of the CWIP amount was financed by AIC's vendors, not its shareholders, therefore the Commission should adopt Staff's adjustment to reduce CWIP by $37,000.

On rebuttal, AIC adjusted its non-Allowance for Funds Used During Construction ("AFUDC") CWIP balances to remove two projects that were also included in 2012 projected plant additions. Staff and AG/AARP, however, propose an adjustment to remove an additional $36,659 from CWIP for the portion of the balance for project 29301 not yet financed by AIC, and therefore still remaining in accounts payable at December 31, 2011. (Id.) AIC opposes this adjustment because the amount at issue in accounts payable was financed by AIC within ten days of year-end 2011, almost two years prior to AIC receiving funds from ratepayers for a return on the investment dollars at issue, and is otherwise consistent with AIC's 2011 FERC Form 1 and Section 9-214(e) of the Act. Based on the Commission's decision in Docket No. 12-0001 however, AIC agrees to remove this additional amount from CWIP for purposes of this proceeding.

The Commission finds that this issue is uncontested, and the proposal by Staff is reasonable, therefore it will be adopted for the purposes of this proceeding.

B. Contested Issues

1. Accrued Vacation Pay

a. AIC Position

AIC notes that Staff witness Ebrey proposes an adjustment to include the liability for accrued vacation pay to the operating reserves that are deducted from rate base, claiming that because the Commission adopted this adjustment in Docket No. 11-0271, it should also be adopted in this case because "the fact pattern here is similar to that in Docket 11-0721." Staff states that in Docket No. 12-0001, the Commission found "no discernible difference between this proceeding and Docket No. 11-0721 that would properly result in disparate ratemaking treatment of the same item between the two dockets," and on that basis adopted the adjustment. (Docket No. 12-0001, September 19, 2012 Order at 59)

AIC notes that it continues to object to treating the accrued liability for vacation pay as an operating reserve, because it is not an operating reserve. AIC states that the accrued liability has no cash associated with it; it is merely an accounting convention required under Statement of Financial Accounting Standards Number 43 to recognize the value of vacation earned but not yet taken. AIC suggests that the record in this proceeding also presents additional data in support of AIC's position. AIC claims that accrued vacation liability has not been deducted by the Commission in past rate cases and is a current liability on AIC's books due and payable within one year. Accordingly, AIC suggests that accrued vacation is not a source of non-investor supplied capital available to finance Rate Base investment. AIC suggests that Table 1 below shows why accrued vacation is not a source of non-investor supplied capital available to finance Rate Base investment, based on a review of the timeline of accruals, payments, and ratepayer funding of the accruals from 2004 through 2011. AIC states that the first column presents the year AIC Vacation Paid was accrued in AIC's financial statements, the second column presents the year those vacation accruals were made to employees and eliminated AIC's liability balance, while the third column presents the 12-month period that the vacation accruals included in payroll costs were included in rates.

As AIC witness Stafford explained, a rate case test year of 2004 was filed in 2005 with new rates received January 2007, so on the first line, calendar year 2007 is listed as the 12 month period vacation accruals were collected in rates. There was no rate case test year filed for 2005, so the 2005 accruals were not recovered in rates. AIC argues that a similar pattern follows based on rate case filings using 2006 and 2008 test years and timing of new rates, with no rate case filings using 2007 and 2009 test years. Since 2010 is the first formula rate year in Docket No. 12-0001, AIC states the date of new rates is listed as October 2012, however, in the pending docket, AIC notes the effective date for new rates will be January 2013, so only 3 months of the calendar year 2010 accrued vacation will collected in rates.

AIC claims that this Table clearly illustrates, by the time AIC collected its first dime of cost recovery from ratepayers for accrued vacation; it had already made payments to employees that eliminated the entire liability for accrued vacation included in payroll costs.

<u>TABLE 1</u>

AIC Vacation Paid Accrued	Payments made to Employees	Costs Recovered from Ratepayers
2004	2005	2007
2005	2006	None
2006	2007	Oct 2008 - Sep 2009
2007	2008	None
2008	2009	May 2010 - Apr 2011
2009	2010	None
2010	2011	Oct 2012 – Dec 2012
2011	2012	2013

AIC states that it should be noted that although accrued vacation is expensed or capitalized on AIC's financials before payments are made, these costs are not included in rates until after they are paid, therefore, these costs do not represent a source of non-investor supplied funds and Staff and intervenors' adjustment should be rejected.

While Staff and intervenors urge the Commission in Initial Briefs to adopt the same adjustment proposed here to maintain consistency in formula rate filings, AIC argues that the record in this proceeding demonstrates that the premise for the adjustment is fundamentally flawed. To adopt the same adjustment for the sake of consistency, when the manifest weight of evidence in this proceeding demonstrates the adjustment is improper, would not be appropriate. Therefore, AIC contends that Staff, AG/AARP and CUB's rate base deduction should be rejected.

b. Staff Position

Consistent with the conclusion in Docket No. 12-0001, Staff recommends that the Commission approve Staff's recommendation to reflect accrued vacation pay reserve as a reduction to rate base. (September 19, 2012 Order at 58-59) Staff recommends that the liability for accrued vacation pay should be deducted from rate base since the accrual is funded by ratepayers and the ADIT associated with the vacation accrual is included in the rate base. Staff notes that the Commission adopted a similar adjustment in the initial Commonwealth Edison Company ("ComEd") formula rate proceeding to reduce rate base by the amount of accrued vacation pay not already reflected in its cash working capital ("CWC") adjustment. (Docket No. 11-0721, May 29, 2012 Order at 69-70) Likewise, Staff notes that the Commission's Order in the initial AIC formula rate case made the same finding, stating that there is no discernible difference in the facts between this case and Docket No. 11-0721 that would warrant a different regulatory treatment. (Docket No. 12-0001, September 19, 2012 Order at 58-59) Staff suggests that since no additional or different evidence that would warrant a different regulatory treatment has been presented in this case, the Commission should reach the same conclusion in this proceeding.

Staff notes that vacation is usually not paid until a year or more after it is earned, and it is this lag between the accruals and the cash payments that creates a constant non-investor source of funds which should be deducted from rate base similar to other operating reserves. As shown on AIC's responses to Staff data request ("DR") TEE 2.08 Attach (Attachment A) and the AG's DR AG 1.03 (Attachment B), there is a constant balance of funds held in reserve. While the total balance may go up or down over time, Staff states that the reserve is never completely depleted.

Although AIC witness Stafford claims that the vacation reserve is completely depleted each year and is replaced with entirely new accruals, Staff claims that AIC's response to DR AG 1.03 (Staff Ex 1.0, Attachment B) shows that an increasing balance is reflected as accrued vacation pay on AIC's books each month during 2011. Likewise, Staff suggests that AIC response to Staff DR TEE 2.08 Attach (Staff Ex. 1.0, Attachment A) shows that the balance of accrued vacation pay for each year presented remains fairly consistent.

Staff avers that Mr. Stafford provides a misleading and overly simplistic view of how ratemaking functions. Staff notes that according to Mr. Stafford's table, for any year that was not the basis for the test year revenue requirement, the vacation paid in that year is never recovered from ratepayers; however Staff suggests that this is simply incorrect. To the extent that accrued vacation pay has been recorded to payroll expense and is not removed through a ratemaking adjustment, Staff submits that that vacation pay is funded by ratepayers. Upon cross-examination, Staff notes that Mr. Stafford admitted that the entry recorded by AIC to accrue vacation pay is a credit to the liability account and a debit to payroll expense (or capitalized payroll)., and that AIC did not make an adjustment to remove that accrual from payroll expense included in the formula rate schedule on Formula Rate Sch. FR C-1 Line 1. While Mr. Stafford makes a point of explaining that the liability for accrued vacation at any point in time is made up of vacation earned for different calendar years, Staff believes that this explanation does nothing to discount the fact that an almost constant amount for accrued vacation pay exists on AIC's books at any point in time.

Staff complains that AIC's arguments presented in its Initial Brief concerning accrued vacation pay persist in clouding the relevant facts in this case, with AIC claiming that there is no cash associated with the accrued liability and that it is simply an accounting convention required to recognize the vacation time earned but not taken. Staff opines that AIC's argument ignores the fact that the accrued vacation is recorded as a payroll expense and is included in the revenue requirement operating statement on which rates are set. As such, Staff notes that the ratepayers are funding the accrued vacation liability prior to the time the vacation is actually paid in cash; therefore the shareholders have use of those funds for potentially a year or more. Since AIC did not make a ratemaking adjustment to remove the accrued vacation from payroll expense, Staff suggests that AIC admitted that ratepayers have funded the accrual. Since the only additional argument provided by AIC in this case simply serves to support Staff and the intervenors' positions, the Commission should not stray from its decision in Docket No. 12-0001 on this issue in the instant case.

For the foregoing reasons, Staff recommends that the Commission adopt Staff's recommendation that the liability for accrued vacation pay be deducted from rate base.

c. AG/AARP Position

AG/AARP note that vacation pay is accrued and expensed by AIC in the year prior to the employee receiving payment, therefore there is an approximate one-year lag between the accrual of vacation pay expense and the actual cash disbursement in payment of the liability for vacation pay.

While AIC excluded this vacation accrual from its calculation of its CWC requirement, AG/AARP note that vacation pay is not distinguished from other elements of payroll expense and is implicitly included in the calculation of CWC as part of total payroll expense, which carries a lag in payment, according to AIC, of 11.39 days. AG/AARP state that this lag does not capture the much longer lag in payment of vacation pay. AG/AARP witness Effron testifies that although the vacation pay expense is included in the total payroll expense reflected in the CWC study, the longer lag in payment for this item has not been taken into account. As such, AG/AARP contend that the accrued liability for this item should be treated as an operating reserve, an expense that has been accrued but not been paid, and deducted from rate base. AG/AARP note that Staff witness Ebrey and CUB witness Smith concurred on this point.

AG/AARP submit that the Commission has concluded in both the ComEd (Docket No. 11-0721) and AIC (Docket No. 12-0001) formula rate orders that this vacation pay amount should be treated as an operating reserve and deducted from rate base. (See Docket No. 11-0721, May 29, 2012 Order at 69-70 and Docket No. 12-0001, September 19, 2012 Order at 58-59) In its adoption of the AG/AARP rate base deduction recommendation, the Commission stated:

> The Commission finds that the proposed adjustment of AG/AARP, as endorsed by Staff, results in the proper ratemaking treatment of this item. It appears to the Commission that there is no discernible difference between this proceeding and Docket No. 11-0721 that would properly result in disparate rate making treatment of the same item between the two dockets. The Commission therefore adopts AG/AARP's proposed adjustment that results in a total deduction to rate base of $11,706,000. (Docket No. 12-0001, September 19, 2012 Order at 58-59)

AG/AARP contend that the facts in the instant case that support adoption of the AG/AARP adjustment have not changed. As noted in the testimony of Staff witness Ebrey, vacation pay accrues throughout the year and is routinely paid out in the following year. AG/AARP submit that the lag between the accruals and the cash payments creates a constant non-investor source of funds which should be deducted from rate base similar to other operating reserves. As noted by Ms. Ebrey, while the total balance may go up or down over time, the reserve is never completely depleted.

Although AIC argues that because the accrued vacation pay is “due and payable within one year” it is therefore not a source of non-investor supplied capital available to finance rate base investment, AG/AARP note that during cross examination, Mr. Stafford likewise insisted that in fact the accrual for vacation pay is paid off each year. However, AG/AARP state that the fact that the accrued vacation is payable within one year has nothing to do with whether it is a source of non-investor supplied capital noting that as the vacation accrual from the prior year is paid off, it is replaced with accruals for vacation pay in the current year. In effect, AG/AARP submit that the accrued vacation pay becomes a continuing, permanent balance.

AIC witness Stafford further purports to show that vacation pay is not a source of non-investor supplied capital because it has not been fully recovered in rates in prior cases. AG/AARP suggest this argument is illusory however, suggesting that, for instance, AIC’s 2005 rates reflected the vacation pay that was accrued in whatever test year used to establish the rates in effect in 2005, despite the fact that there was not a rate case in 2005. AG/AARP contend that Mr. Stafford never established that the vacation accrual in 2005 was materially different from the vacation accrual in the applicable test year. As AG/AARP witness Effron notes, just because a given year was not a test year in a rate case does not mean that the expense incurred in that year were not recovered from ratepayers, as AIC suggests. Further, AG/AARP note that the accrual from the 2004 test year was recovered in rates and continued to be recovered in rates for as long as the rates based on the 2004 test year were in effect. AG/AARP assert that AIC has provided no evidence that the accrual in the 2004 test year was not a reasonable representation of the prospective vacation accruals going forward, as is the case for any other test year expense.

AG/AARP state that the average reserve for accrued vacation over the course of 2011 was $12,888,000., with the jurisdictional amount of this balance being $11,994,000. Of this amount, AG/AARP suggest that $374,000 was implicitly recognized in the CWC allowance, while the difference, $11,620,000, should be treated as an operating reserve and deducted from rate base. In addition, AG/AARP contend that the related deferred tax debit balance included in rate base should be modified so that it is consistent with the balance that is deducted from rate base. Based on the combined income tax rate of 41.175%, AG/AARP state that the deferred tax debit balance related to the 2010 accrued vacation pay is $4,939,000, which is $996,000 less than the year-end deferred tax debit balance of $5,935,000 reflected on AIC Ex. 1.2, WP 4. AG/AARP recommend that the deferred tax debit balance related to accrued vacation should be decreased by $996,000, which increases the rate base adjustment related to accrued vacation to $12,617,000.

AG/AARP submit that the evidence shows that AIC maintains a continuous accrual of non-investor supplied funds for vacation pay which should be deducted from rate base similar to other operating reserves. In addition, there simply is no evidence as to why the Commission should deviate from its two most recent rulings on this issue, including its September 19, 2012 AIC formula rate order. The Commission should adopt the AG/AARP adjustment, which reduces the AIC rate base by $12,617,000.

d. CUB Position

CUB notes that though AIC included in rate base ADIT on Vacation Pay, it did not take the liability balance for Accrued Vacation Pay into account in determining rate base. CUB asserts that the accrued liability for vacation pay should be deducted from rate base, consistent with the Commission's decisions in Docket Nos. 11-0721 and 12-0001.

CUB notes that initially, AIC did not account for the vacation pay accrual in any way. CUB witness Smith testified that, though one way of addressing the lag in payment of vacation pay could be to reflect a very long lag in the lead-lag study, the more appropriate method of adjusting AIC's rate base to account for accrued vacation liability is to treat the balance as a direct offset to rate base. On rebuttal, AIC amended its lead-lag study to reflect vacation accrual; however CUB complains that this adjustment is not adequate. CUB states that rather than deducting the accrued vacation balance from rate base, as Mr. Smith recommended, AIC made an adjustment to the payroll expense lead.

CUB suggests that the basic matching principal requires that if the related ADIT debit balances are included in rate base, then the accrued liabilities giving rise to those deferred balances should be included in the operating reserves deducted from rate base. CUB notes that the Commission addressed this same issue in Docket Nos. 12-0001 and 11-0721. In Docket No. 11-0721 Order, the Commission stated, "While ComEd argues that any accrued vacation pay is short-term in nature, Staff, the AG/AARP, CUB/City all point out that the balance on this item remains constant from one year to the next, due to the fact that, as ComEd's employees use vacation pay, they accrue more vacation pay." (Docket No. 11-0721, May 29, 2012 Order at 69-70.) CUB notes the Commission ultimately concluded in Docket No. 11-0721 that the accrued vacation is a source of funds (i.e., a source of capital) for the utility and should be reflected as a reduction to rate base. CUB states that in Docket No. 12-0001, the Commission stated that there was no discernible difference between Dockets Nos. 12-0001 and 11-0721 that should result in disparate ratemaking treatment of the same item between the two dockets. CUB opines that the same circumstances exist in this docket; therefore the Commission should remain consistent with its previous orders and deduct $11.982 million from rate base.

CUB notes that AIC purports to illustrate in a table on page 7 of its Initial Brief, that accrued vacation is not "non-investor supplied funds" because the costs are not included in rates until after they are paid; however, CUB argues that the point in time at which a particular cost is recovered from ratepayers does not impact whether it should be deducted from rate base, or whether it is in fact a source of non-investor supplied funds. CUB notes that at every month-end of 2011 AIC had a balance of accrued vacation pay liability, which indicates that the accrued vacation pay liability is a source of non-investor supplied funds that is continually replenished. CUB argues that the average 2011 balance of accrued vacation pay liability should therefore be deducted from rate base, net of related ADIT. CUB complains that AIC's table also ignores the ADIT impact of this accrued liability; it is improper and a mis-match to include an addition to rate base for the debit-balance ADIT, without making the corresponding rate base deduction for the accrued vacation liability to which that ADIT relates. CUB suggests that AIC's proposal ignores the basic matching principal, and is contrary to previous Commission decisions. CUB urges the Commission to ignore AIC's attempts to relitigate this issue and reject its claim that the accrued vacation pay does not represent a source of utility funds that should be deducted from rate base.

e. Commission Conclusion

The Commission notes that it has concluded in both the ComEd (Docket No. 11-0721) and AIC (Docket No. 12-0001) formula rate orders that this vacation pay amount should be treated as an operating reserve and deducted from rate base. (See Docket No. 11-0721, May 29, 2012 Order at 69-70 and Docket No. 12-0001, September 19, 2012 Order at 58-59) In its adoption of the AG/AARP rate base deduction recommendation in Docket No. 12-0001, the Commission previously stated:

> The Commission finds that the proposed adjustment of AG/AARP, as endorsed by Staff, results in the proper ratemaking treatment of this item. It appears to the Commission that there is no discernible difference between this proceeding and Docket No. 11-0721 that would properly result in disparate rate making treatment of the same item between the two dockets. The Commission therefore adopts AG/AARP's proposed adjustment that results in a total deduction to rate base of $11,706,000. (September 19, 2012 Order at 58-59)

It appears to the Commission that the facts in the instant case have not changed. As noted in the testimony of Staff witness Ebrey, vacation pay accrues throughout the year and is routinely paid out in the following year. It appears to the Commission, as argued by Staff, that the lag between the accruals and the cash payments creates a constant non-investor source of funds which should be deducted from rate base similar to other operating reserves. The Commission believes that Staff Ex. 1.0, Attachments A and B provide visual evidence of this constant balance of ratepayer-supplied funds held in reserve. As noted by Ms. Ebrey, while the total balance may go up or down over time, it does not appear that the reserve is ever completely depleted.

The Commission recognizes AIC's position that because the accrued vacation pay is "due and payable within one year," it is not a source of non-investor supplied capital available to finance rate base investment. It appears to the Commission, however, that the fact that the accrued vacation is payable within one year has nothing to do with whether it is a source of non-investor supplied capital. In fact, the Commission notes that as the vacation accrual from the prior year is paid off, it is replaced with accruals for vacation pay in the current year. Further, as noted by AG/AARP witness Effron, the fact that the accrued vacation is payable within one year has nothing to do with whether it is a source of non-investor supplied capital. In fact, the Commission believes the record evidence shows that as the vacation accrual from the prior year is paid off, it is replaced with accruals for vacation pay in the current year. In effect, the accrued vacation pay becomes a continuing, permanent balance. The Commission finds that the adjustment proposed on this issue by AG/AARP, Staff, and CUB is appropriate and reasonable in this proceeding, therefore the proposed adjustment is hereby adopted.

2. Accumulated Deferred Income Taxes – Financial Interpretation Number 48

a. AIC Position

AIC notes that this issue concerns the appropriate ratemaking treatment of liabilities under Financial Interpretation Number 48 ("FIN 48") of so-called "FIN 48 liabilities" that was addressed in Docket No. 12-0001. In that case, the Commission adopted the proposal to reduce rate base to reflect the FIN 48 balances. As with other issues in this proceeding, AIC continues to contest this issue in order to preserve its right to rehearing and appeal. In addition, however, AIC submits that the record in this proceeding makes clear that AIC's position on FIN 48 should be adopted and the position of Staff and intervenors rejected. AIC asserts that there are three reasons for this:

- There is a cost associated with FIN 48 amounts, and so they cannot be treated for ratemaking purposes as a cost free source of capital.
- Taking of uncertain tax positions benefits ratepayers.

- The proposals of Staff and intervenors address the protection of ratepayers in the less likely scenario but ignore the impact on the utility of the more likely scenario, thereby eliminating the incentive to the utility to take the uncertain position that benefits ratepayers.

AIC states that FIN 48 requires that the amount of tax that AIC and its outside auditors have concluded "more likely than not" will eventually be paid to taxing authorities in connection with the uncertain position must be reflected on the balance sheet as a tax liability, and interest and penalties must also be accrued. AIC argues that Staff and certain Interveners believe AIC's FIN 48 amounts of $8.59 million are of the same character as ADIT and should be deducted from rate base for the same reason ADIT is deducted from rate base; i.e., because ADIT represents a source of cost-free capital to the utility.

AIC submits however, that FIN 48 amounts are not a "cost free" source of capital, noting that the FIN 48 Interpretation document itself requires that "When the tax law requires interest to be paid on an underpayment of income taxes, an enterprise shall begin recognizing interest expense in the first period the interest would begin accruing according to the provisions of the relevant tax law." Likewise, AIC notes that applicable penalties must also be recorded.

AIC notes that CUB recognizes this, with CUB witness Smith explaining that if the uncertain tax positions were resolved by the tax authority fully disallowing the uncertain amounts, AIC would have to pay the taxes with interest. Mr. Smith also states that the interest paid would be tax-deductible, and AIC would have had the use of the money (similar to a government loan) during the period before payback for only the cost of the interest. "AIC submits that "only the cost of the interest" is still a cost to AIC associated with the FIN 48 amounts. AIC claims that just like debt is not cost free, neither are FIN 48 amounts.

While the actual interest expense on FIN 48 amounts may be low or zero in any given year, AIC argues that this does not mean the interest cost component of FIN 48 amounts does not exist, or that one can assume based on that given year that the FIN 48 amounts are "cost free." AIC suggests that such an assumption would be the same as saying the customer deposits are "cost free" simply because Commission's customer deposit interest rate is currently zero. Since applicable interest must be accrued on FIN 48 amounts, AIC claims that the FIN 48 amounts are not "cost free" and so the position of Staff and Interveners should be rejected.

If, contrary to the expectations of the experts (i.e., under the less likely scenario), AIC is able to prevail in the assertion of an uncertain tax position, AIC notes that at that point the non-ADIT capital would be re-characterized as ADIT capital and deducted from rate base, to the customer's benefit. AIC alleges that the record in this case shows that AIC took aggressive, uncertain tax positions, that ultimately, 60% of those uncertain tax positions were allowed by the taxing authority, and ratepayers ultimately received a benefit in the form of increased ADIT. AIC claims that its prudently aggressive tax positions created over $6 million of ADIT that wouldn't otherwise exist, and that these ADIT amounts have been reflected for ratemaking purposes in this filing.

AIC argues that deducting FIN 48 balances from rate base, as Staff and Interveners recommend, unfairly punishes utilities that take aggressive tax positions that benefit ratepayers. While the Staff and Interveners purport to protect ratepayers, AIC suggests that the "protection" of adding FIN 48 to ADIT balances is protection against the less likely outcome—that an uncertain tax position will be allowed and the deductions reclassified as ADIT. If the more likely outcome occurs, and FIN 48 balances are paid to the government, AIC argues that the utility is penalized by the Staff and Intervener approach. AIC notes that these funds, once repaid to the government, are not, by definition, "available" to the utility, whether on a "cost-free" basis or otherwise.

When funds produced by the assertion of an uncertain tax position are treated as cost-free capital, added to ADIT, and deducted from rate base, AIC believes that it is not in its interest to take more aggressive tax positions, because a rate base reduction occurs for sums that are likely to be repaid with interest when assessed by the government. AIC claims that the need to preserve this incentive has been recognized in other jurisdictions. AIC cites <u>In Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service</u>, Case No. ER-2008-0318, in which the Missouri Commission found: "Both ratepayers and shareholders benefit when AmerenUE takes an uncertain tax position with the Internal Revenue Service ("IRS"), because saving money on taxes benefits the company's bottom line and reduces the amount of expense the ratepayers must pay." Order, Case No. ER-2008-0318, 2009 Mo. PSC Lexis 71, *55 (Mo. PSC Jan. 27, 2009). The Missouri Commission concluded that "[t]he best way to encourage AmerenUE to continue to take uncertain tax positions is to treat the company fairly in the regulatory process." It found treating FIN 48 liabilities as ADIT is unfair to the utility because "[i]f the ultimate outcome before the IRS matches the FIN 48 analysis . . . there would be no deferral of tax and no means by which AmerenUE would recover the amount that reduced rates, but was not actually realized by the company." AIC recommends that the Commission adopt a similar result here.

AIC submits that the position of Staff, AG/AARP, and CUB continues to ignore the fact that utilities should be encouraged to adopt uncertain positions, otherwise, the incremental zero-cost capital (ADIT) cannot come into being. AIC contends that deducting FIN 48 balances from rate base as Staff and intervenors recommend in their Initial Briefs unfairly punishes utilities that take aggressive tax positions that benefit ratepayers. AIC notes that adding FIN 48 to ADIT balances is protection against the less likely outcome that an uncertain tax position will be allowed, and the deductions reclassified as ADIT. AIC avers that if the more likely outcome occurs, and FIN 48 balances are paid to the government, the utility is penalized by the Staff and Intervener approach.

b. Staff Position

Staff recommends that the Commission adopt its recommendation that, for ratemaking purposes, FIN 48 balances should be included in the ADIT balance that is a deduction from rate base. Staff notes that the Order in Docket No. 12-0001 found that the FIN 48 balances represent a source of cost-free capital and thus, the FIN 48 balances should be included as a reduction to rate base through ADIT. (Docket No. 12-0001, September 19, 2012 Order at 43-44) Since no new arguments have been presented in this case, Staff suggests that the Commission should reach the same conclusion in this proceeding.

Staff notes that its recommendation is the same recommendation as proposed by AG/AARP and CUB. While AIC argues that since these balances represent uncertain tax positions which will only be determined upon the conclusion of an IRS audit, and therefore they should not be used to reduce rate base through ADIT, Staff submits that a review of the findings of IRS audit results from 2005 – 2007 audit cycles shows that of the FIN 48 amounts recorded by AIC, only 39.5% were actually found to be payable.

Staff avers that in its prior formula rate case, AIC acknowledged that: (1) AIC has in its possession a quantity of capital which it procured by means of filing income tax returns, which was clearly not supplied by shareholders; and (2) the capital at issue resulted from claiming tax deductions which experts have concluded AIC is more likely than not going to lose. Staff notes that when AIC loses the deductions, it will pay the capital back to the taxing authorities with interest.

In its Reply Brief, Staff notes that under the treatment proposed by Staff and the intervenors, AIC will suffer no risk, quoting as follows:

> That is, if some portion of the FIN 48 liability is ultimately paid back to the government, the Company will be made whole when the rate base is reconciled. But as long as the FIN 48 liability is outstanding, it represents a source of non-investor supplied funds to the Company and should be included in the ADIT deducted from the Company's rate base. (AG/AARP Initial Brief at 12)

For the foregoing reasons, the Commission should adopt Staff's recommendation that, for ratemaking purposes, FIN 48 balances should be included in the ADIT balance that is a deduction from rate base.

c. AG/AARP Position

AG/AARP state that the ADIT-FIN 48 balances recorded by AIC represent the amount of deferred tax liabilities that have been reclassified to FIN 48 liabilities related to uncertain tax positions that ultimately may have to be paid to the government. AG/AARP note that AIC reduced the balance of ADIT deducted from its delivery services plant in service, which has the effect of increasing the rate base and AIC's revenue requirement, to reclassify certain ADIT related to uncertain tax positions. AG/AARP opine that the balance of ADIT FIN 48 breaks down as follows: $7,381,000 for Federal and $1,208,000 for State. AG/AARP note that the effects of these debit balances is to reduce the ADIT deducted from plant in service in the determination of rate base, thereby increasing the size of the rate base.

AG/AARP contend that until these deferred tax liabilities are actually paid to the relevant taxing authorities, they represent non-investor supplied funds that are available to AIC. In addition, AG/AARP witness Effron states that he believes that it is highly likely that the FIN 48 liabilities will not have to be paid and should be treated as ADIT for the purpose of determining AIC's rate base.

AG/AARP claim that the record evidence supports that opinion, noting that in response to AG DR 1.08, AIC stated that forecasted interest expense on the FIN 48 liabilities for 2012 is $0. AG/AARP suggest that this implies that AIC believes that it is likely that the FIN 48 liabilities will not have to be paid. AG/AARP avers that if the tax deductions at issue are ultimately disallowed, AIC would be required to pay the taxes due, with interest, and applicable accounting rules require that interest be accrued on the taxes that are deemed likely to be paid. If AIC is not accruing interest, AG/AARP submit that AIC must believe that taxes in question will not have to be paid.

Mr. Effron noted that one possible reason that the taxes will not have to be paid is the availability of net operating loss ("NOL") carry-forward. That is, Mr. Effron states that even if the "uncertain" tax positions result in disallowances, the disallowances will not actually result in tax payments to the extent that there are NOLs available to offset those disallowances. In fact, AIC includes the deferred tax debit balances related to the NOLs in rate base; that is, the NOLs reduce the net credit balance of ADIT. To the extent that these deferred tax assets can be used to offset FIN 48 income tax liabilities, AG/AARP contend that there is a double counting of the NOLs and the FIN 48 deferred tax items in the AIC ratemaking treatment, and it is improper to include both in rate base.

AG/AARP argue that there simply is no dispute that this balance represents non-investor supplied funds as long as the balance is outstanding, noting that the rate base determined in this case will be reconciled to the actual rate base for 2013. To the extent that any of the FIN 48 liability has been paid, they note that such repayment will be reflected in the determination of the actual 2013 rate base. However, to the extent that AIC still has a FIN 48 liability outstanding in 2013, AG/AARP submit that that balance should be included in the ADIT balance deducted from the actual rate base used in the reconciliation, as by definition such amounts will not have been paid.

AG/AARP submit that the rate base deduction for the FIN 48 liability poses no risk to AIC as long as the rate base originally used to establish rates in a given filing is ultimately trued-up to the actual rate base. AG/AARP note that if some portion of the FIN 48 liability is ultimately paid back to the government, AIC will be made whole when the rate base is reconciled, however as long as the FIN 48 liability is outstanding, it represents a source of non-investor supplied funds to AIC and should be included in the ADIT deducted from AIC's rate base. AG/AARP contend that Staff witness Ebrey concurred on this point, while CUB witness Smith calculated an identical adjustment for proposed removal of the ADIT FIN 48 debit balance.

AG/AARP note that the Commission recently concurred on this point in its Order in Docket No. 12-0001, AIC's first formula rate filing. There, the Commission noted:

> The Commission notes that IIEC, AG/AARP, and CUB all put forward essentially the same arguments as Staff, and all recommend that the FIN 48 balances be deducted from rate base, suggesting that this decision is in conformity with the FERC guidance on FIN 48. The Commission also recognizes that this issue does not appear to have been present in the ComEd smart grid docket, Docket No. 11-0721. The Commission agrees with Staff and Intervenors' position that the FIN 48 amount represents a source of cost-free capital that should be reflected as a rate base deduction. The Commission does not believe that AIC's position provides any mechanism to protect customers while awaiting an IRS review. The Commission notes that under AIC's position, if the IRS does not disallow the tax deduction associated with the FIN 48 reserve, customers would not receive the benefit of the deferred tax credits in the form of a rate base reduction until the first rate case after tax returns are no longer subject to IRS review and adjustment. The Commission will therefore adopt for this proceeding the proposal to reduce rate base to reflect the FIN 48 balances of $35,695,000 for the federal and $7,993,000 for the state, net of the total expected payments on FIN 48 of $4,070,000, for a net reduction of $39,618,000. (Docket No. 12-0001, September 19, 2012 Order at 43-44)

AG/AARP state that the facts have not changed for purposes of this docket, therefore the Commission should adopt Mr. Effron's adjustment to the rate base calculation.

AG/AARP recognize that AIC continues to oppose the recommended FIN 48 adjustment, however, they note that AIC witness Warren does not disagree that the FIN 48 liabilities represent non-investor supplied funds. AIC also claims that the FIN 48 liabilities "should only reduce rate base after the amounts have been determined to be ADIT – that is, after AIC and its experts have concluded, either independently or as a result of an audit by the taxing authorities, that it is no longer more likely than not that the amounts will be assessed by the government." AG/AARP opine that the problem is that Mr. Warren's asserts that the "best information" for evaluating this proposed adjustment is the date used for the computation of rate base (December 31, 2011) reflected on AIC's books as of that date. They suggest that Mr. Warren would have the Commission ignore record evidence produced in this docket that sheds light on the likelihood of whether AIC will have to pay the deferred tax amounts at issue. They note that he also failed to explain why, if his information indicates that the FIN 48 liabilities will ultimately be paid, AIC is not accruing any interest on these liabilities in 2012.

AG/AARP submit that Mr. Warren's view that the best information available implies a FIN 48 balance of zero is completely unsupported, noting that he fails to cite any information to establish that an assumption of a zero liability is appropriate. AG/AARP suggest that Mr. Warren's view that a zero FIN 48 liability is appropriate is not based on any information, let alone the best information available. Therefore, the Commission should reject Mr. Warren's recommendation.

AG/AARP note in their Reply Brief that the rate base deduction for the FIN 48 liability poses no risk to AIC as long as the rate base originally used to establish rates in a given filing is ultimately trued-up to the actual rate base. That is, if some portion of the FIN 48 liability is ultimately paid back to the government, they state that AIC will be made whole when the rate base is reconciled. As long as the FIN 48 liability is outstanding, AG/AARP contend that it represents a source of non-investor supplied funds to AIC and should be included in the ADIT deducted from AIC's rate base, on which point Staff and CUB both agreed. AG/AARP suggest that the risk that AIC speaks of is simply not there.

AG/AARP argue that the ADIT debit balances related to FIN 48 should be eliminated from the balance of ADIT deducted from plant in service, which, in effect, reverses the reclassification of the ADIT balances to FIN 48 liabilities for the purpose of determining AIC's electric rate base. AG/AARP note that the effect of eliminating the deferred tax debit balances related to FIN 48 is to increase the balance of ADIT by $8,589,000 and to reduce the electric rate base by the same amount.

d. CUB Position

CUB notes that AIC has included in rate base debit balances of ADIT FIN 48 as follows: $7.381 million for Federal and $1.208 million for State. Though AIC claimed deductions on its tax returns and thus avoided paying income taxes on these amounts, CUB avers that AIC nonetheless seeks to ignore this source of non-investor supplied capital for ratemaking purposes. CUB submits that AIC's proposal for the treatment of its FIN 48 amounts would allow it to benefit by taking uncertain tax positions, claiming deductions on its tax returns, and charging ratepayers for deferred income tax expense but failing to reflect the non-investor supplied source of capital represented by the tax benefits claimed on its tax returns.

CUB states that a FIN 48 liability represents the difference between AIC's position taken on a tax return versus the identification of "uncertain" tax positions as required for financial statement reporting. CUB notes that differences in the interpretation of tax law exist, and FIN 48 prescribes procedures to quantify "uncertain" tax positions, for which the estimates are accumulated in a temporary reserve until the position is no longer uncertain. CUB opines that certainty can be achieved by either (1) review of the technical merits of the position by the relevant taxing authority, (2) expiration of the statute of limitations or (3) law change. CUB avers that AIC is attempting to increase rate base because there is an uncertainty with some of its tax positions that have not yet been resolved by an IRS audit, statute expiration, or law change. CUB believes that AIC would prefer to ignore the non-investor supplied source of funding represented by the tax savings it has received, for ratemaking purposes, until the uncertainty perceived by its tax experts is resolved.

CUB states that FIN 48 indicates that an entity shall initially recognize the financial statement effects of a tax position when it is “more likely than not” based on the technical merits that the position will be sustained upon examination, and that “more likely than not” means the likelihood is more than 50 percent. CUB states that the “more likely than not” threshold is a positive assertion that an entity believes it is entitled to the economic benefits associated with a tax position, and the level of evidence to support an entity’s assessment of the technical merits of a tax position is a matter of judgment that depends on all available information. CUB notes that per Financial Accounting Standards Board ASC-740-10-25-8, if the “more likely than not” recognition threshold is not met in the period for which a tax position is taken, an entity shall recognize the benefit of the tax position in the interim period that meets any one of the following three conditions:

1) The more-likely-than-not recognition threshold is met by the reporting date.
2) The tax position is effectively settled through examination, negotiation or litigation.
3) The statute of limitations for the relevant taxing authority to examine and challenge the tax position has expired.

CUB alleges that the financial accounting for uncertain tax positions would require a company with such positions to create a “reserve” relating to the uncertain amounts, however AIC witness Warren argued that “experts” have concluded it is more likely than not that the deductions will be disallowed by the IRS. CUB submits however, that information in the record concerning AIC’s 2011 results shows that AIC’s “experts” had, in fact, substantially over-estimated the uncertain income tax positions in 2010, and significant reversals were thus recorded in 2011. Additionally, CUB notes that AIC’s current forecasted interest expense on the FIN 48 liabilities for 2012 is zero, while AIC has indicated that if applicable, interest would be calculated at the rate of 4%-- an amount which is both tax-deductible and is much lower than AIC’s weighted average cost of capital ("WACC") or return on equity ("ROE"). CUB suggests that ratepayers should not be required to pay a WACC or ROE equivalent on a source of capital that is at best zero-cost and at worst carries a 4% tax-deductible interest cost.

CUB notes that FERC has provided guidance on accounting for uncertainty in income taxes, and according to the FERC guidance, the FIN 48 amounts are required to be treated as ADIT. CUB submits that AIC has not identified any legitimate reason to deviate from the FERC guidance on this issue. CUB argues that the FERC guidance has special relevance to the formula rates being developed in this case, which will be based on FERC Form 1 inputs.

CUB claims that other electric utilities, such as American Electric Power, are appropriately applying the FERC accounting guidance and using for ratemaking purposes the deferred tax balances provided for under the FERC Uniform System of Accounts ("USOA") that reflect their filed tax returns without regard to any FIN 48 adjustments. CUB opines that the FERC accounting guidelines, which are captured in CUB witness Smith's adjustment, reflect the most appropriate regulatory accounting and ratemaking treatment of these tax deductions and should be required for AIC in the current case.

CUB notes that the 2010 impacts of FIN 48 have been considered and decided in AIC's initial formula rate filing, the Commission's 12-0001 Order. CUB states that the Commission agreed with CUB, Staff and other intervenors that FIN 48 amounts represent a source of non-investor supplied cost-free capital that should be reflected as a rate base deduction. CUB indicates that the Commission noted that AIC's position does not provide any mechanism to protect customers while awaiting an IRS review, and that if the IRS does not disallow the tax deduction associated with the FIN 48 reserve, customers would not receive the benefit of the deferred tax credits until the first rate case after that IRS decision is made. CUB avers that the decision in Docket No. 12-0001 was consistent with the Proposed Order in AIC's most recent electric rate case, Docket No. 11-0279 (which was withdrawn by AIC) and with the recent Commission decision in Docket No. 11-0767, Illinois American Water's most recent rate case. CUB suggests that the Commission's previous decisions on this issue are correct, and, as AIC's position is unfair to customers, it should be rejected.

e. Commission Conclusion

As AG/AARP point out, the rate base deduction for the FIN 48 liability poses no risk to AIC as long as the rate base originally used to establish rates in a given filing is ultimately trued-up to the actual rate base. That is, if some portion of the FIN 48 liability is ultimately paid back to the government, AIC will be made whole when the rate base is reconciled. But as long as the FIN 48 liability is outstanding, it represents a source of non-investor supplied funds to AIC and should be included in the ADIT deducted from AIC's rate base. Staff witness Ebrey concurred on this point and CUB witness Smith calculated an identical adjustment to Mr. Effron's proposed removal of the ADIT FIN 48 debit balance. The problem with AIC's response to the proposed adjustment is its assertion that the "best information" for evaluating this proposed adjustment is "the date used for the computation of rate base (December 31, 2011) . . . reflected on AIC's books as of that date." In other words, AIC witness Warren would have the Commission ignore record evidence produced in this docket that sheds light on the unlikelihood of AIC's having to pay the deferred tax amounts at issue. Mr. Warren also failed to explain why, if his information indicates that the FIN 48 liabilities will ultimately be paid, AIC is not accruing any interest on these liabilities in 2012.

The Commission recently concluded that a FIN 48 adjustment was appropriate in Docket No. 12-0001, AIC's first formula rate filing, where it found:

> The Commission notes that IIEC, AG/AARP, and CUB all put forward essentially the same arguments as Staff, and all recommend that the FIN 48 balances be deducted from rate base, suggesting that this decision is in conformity with the FERC guidance on FIN 48. The Commission also recognizes that this issue does not appear to have been present in the ComEd smart grid docket, Docket No. 11-0721. The Commission agrees with Staff and Intervenors' position that the FIN 48 amount represents a source of cost-free capital that should be reflected as a rate base deduction. The Commission does not believe that AIC's position provides any mechanism to protect customers while awaiting an IRS review. The Commission notes that under AIC's position, if the IRS does not disallow the tax deduction associated with the FIN 48 reserve, customers would not receive the benefit of the deferred tax credits in the form of a rate base reduction until the first rate case after tax returns are no longer subject to IRS review and adjustment. The Commission will therefore adopt for this proceeding the proposal to reduce rate base to reflect the FIN 48 balances of $35,695,000 for the federal and $7,993,000 for the state, net of the total expected payments on FIN 48 of $4,070,000, for a net reduction of $39,618,000. (September 19, 2012 Order at 43-44)

The Commission finds that the facts have not changed for purposes of this docket, as the evidence recited above details. Therefore, the same finding is appropriate as to this issue. The Commission finds that the record evidence in this proceeding supports the proposed adjustment of Staff and AG/AARP. Mr. Effron's proposed adjustment to the rate base calculation is hereby adopted.

3. Accumulated Deferred Income Taxes – Projected Additions

a. AIC Position

AIC indicates that while it is cognizant of the Commission's findings on this issue in Docket Nos. 11-0721 and 12-0001, it recognizes that various findings are still subject to appeal. AIC contends that the Electric Infrastructure Modernization Act ("EIMA") is clear: for both the initial and updated formula rate inputs, the Act requires adjustments to the FERC Form 1 data to reflect "projected plant additions and correspondingly updated depreciation reserve and expense for the calendar year in which the" tariff and data or inputs are filed. (See 16-108.5(c)(6), (d)(1)) AIC argues that no other items are to be "updated," although Staff and intervenors argue that an additional update—to reflect ADIT generated by 2012 plant additions, should be made. AIC suggests that such an adjustment is contrary to the plain language of the EIMA, and Staff and intervenors are reading into the EIMA a requirement that simply is not there. No other adjustments are required—specifically, there is no mention of a "corresponding" adjustment for ADIT. (See e.g., Northern Moraine Wastewater Reclamation Dist. v. Ill. Commerce Comm'n, 392 Ill. App. 3d 542, 565, 912 N.E.2d 204, 225 (2nd Dist. 2009) ("[T]he enumeration of one thing in a statute is construed as the exclusion of all others.") That Staff and intervenors believe such additional adjustment is necessary to guard against overstated rate base is of no consequence. AIC argues that the general principle is that "it is not within the province of an administrative agency or court to take from or enlarge the meaning of a statute by reading into it language which will, in the opinion of either, correct any supposed omission or defects." American Steel Foundries v. Gordon, 404 Ill. 174, 180-81 (1949).

While Staff and intervenors claim an adjustment for ADIT for future plant is necessary to guard against overstated rate base and artificially increased rates, AIC contends that the fact that its formula rates will not reflect ADIT on projected plant does not mean that rate base will be "overstated." AIC argues that by the time rates are in effect for each successive update proceeding, AIC will have actually incurred the capital costs for that projected year.

AIC submits that even if Staff and intervenors' concern was valid from a theoretical perspective, it is irrelevant for formula ratemaking purposes. AIC states that formula rates are to be established based on "actual costs" and reconciled annually with "actual costs," therefore initial rates must reflect actual ADIT as reported in FERC Form 1. When these rates are reconciled in 2013, AIC notes that the 2012 FERC Form 1 will report actual ADIT recognized in AIC's books for calendar year 2012. Any over- or under-recovery produced by rates in effect during 2012 will show up as an adjustment to rates established in 2013 (and effective as of January 2014). AIC argues that establishing and reconciling rates based on actual costs ensures that customers will pay rates based on actual costs—no more and no less.

While Staff contends in its Initial Brief that AIC's "sole argument" related to this issue hinges on the plain language of the EIMA, AIC asserts that this is where the issue should begin and end. As stated, AIC argues that the plain language—and elementary tenets of statutory construction—demand AIC's interpretation of the Act. Nonetheless, this is not AIC's "sole argument," as AIC submits that Staff and intervenors' ADIT adjustment also is superfluous and irrelevant in light of the EIMA's new rate-setting scheme premised on actual costs and reconciliations. AIC avers that those additional justifications dispose of the ADIT adjustment.

b. Staff Position

Staff recommends that the Commission accept the AG/AARP, CUB, and Staff adjustments to the balance of ADIT to recognize the growth in estimated ADIT directly related to the 2012 projected plant additions. The Commission found, in Docket No. 12-0001, that it was appropriate to update the ADIT balances as requested by Staff and intervenors. (Order, Docket No. 12-0001, September 19, 2012, p. 53) Staff notes that the position advanced by Staff and intervenors is the same in the instant proceeding and in Docket No. 12-0001; therefore Staff argues that the Commission should reach the same conclusion in this proceeding.

Staff opines that the Commission adopted a similar adjustment in Docket No. 11-0721, the ComEd formula rate proceeding. In that proceeding, the Commission concluded that a failure to make this adjustment would allow ComEd an interest-free loan at the ratepayers' expense for several months and would artificially increase rates until the time when an order in the 2011 reconciliation docket takes place. (Docket No. 11-0721, May 29, 2012 Order at 59-60) The Commission, in discussing its conclusion on this same issue, stated in Docket No. 11-0721:

> However, the statute is silent altogether with regard to ADIT and with regard to many other items that all agree must be included in, or deducted from, rates. If the Commission were to ignore ADIT on ComEd's plant investments, we would be ignoring basic accounting principles and appellate precedent. (See Ameren Illinois Co. v. Ill. Commerce Comm., 2012 IL. App. (4th) 100962 at 31, 2012 Ill. App. LEXIS 175 (4th Dist. 2012), determining, with regarding to an ADIT adjustment to Ameren's rate base, that Section 9-211 of the Public Utilities Act requires that rate base cannot exceed the investment value that a utility actually uses to provide utility services.). (Order at 59)

Staff suggests that AIC's sole argument is that the language of Section 16-108.5(c)(6) and 16-108.5(d)(1) of the Act does not expressly call for adjustments for the projected impact of ADIT to the FERC Form 1 data, however Staff contends that this argument is unavailing. Staff avers that AIC completely ignores the effect of bonus depreciation, which will significantly increase ADIT. Staff recommends that the Commission find it is appropriate under the facts presented in this docket to update the ADIT balances as requested by Staff, AG/AARP, and CUB.

c. AG/AARP Position

AG/AARP note that AIC included $227,912,000 of 2012 projected plant additions in its delivery services rate base rate base, and that it also recognized an associated increase in the balance of accumulated depreciation of $152,944,000 for 2012. AG/AARP state that the net effect is to increase rate base by $74,968,000. AG/AARP witness Effron proposes to modify AIC's net adjustment to rate base for 2012 additions to plant in service, based on AIC's failure to recognize the growth in ADIT directly related to the 2012 projected plant additions. In the circumstances of this filing, Mr. Effron testifies that it is appropriate to include the effect of the ADIT generated by the 2012 plant additions in the calculation of the delivery services rate base.

AG/AARP aver that when AIC reconciles the revenue requirement for 2013 developed in this case to the actual 2013 revenue requirement in its 2014 filing, there is no question that the rate base used in the actual revenue requirement calculation will reflect the actual balances of ADIT in 2013. Therefore, AG/AARP claim that the ADIT generated by the 2012 plant additions will ultimately be included in the calculation of the 2012 delivery services rate base. Unlike the other rate base issues addressed in this testimony, they state that this issue will eventually be resolved by the reconciliation. Mr. Effron notes that there would be little purpose to propose an adjustment to increase ADIT if the only effect would be to increase the difference between the rate base used in this filing and the actual 2013 rate base. That said, in the circumstances of this case, Mr. Effron testifies that it does not appear that recognition of the ADIT generated by the 2012 plant additions will increase the difference between the inception rate base and the actual, reconciled rate base.

AG/AARP aver that the facts in this case show that the existence of 50% bonus depreciation in 2012 provides AIC with a tax deduction equal to one-half of the amount of additions to plant in service, which will lead to growth in the balance of ADIT in 2012 well in excess of the growth that would take place in the absence of the bonus depreciation. AG/AARP note that Mr. Effron calculated the increase in the balance of ADIT related to 2012 plant additions as $43,990,000, as shown on his Schedule DJE-1.4, attached to AG/AARP Ex. 2.0. As such, the balance of ADIT deducted from plant in service in the determination of the delivery services rate base should be increased by this amount. Importantly, Mr. Effron notes that in the circumstances of this case, he believes that this adjustment would tend to reduce, rather than increase, any discrepancy between the inception rate base in this case and the actual 2013 rate base. AG/AARP state that Staff witness Chang and CUB witness Smith proposed similar adjustments.

AG/AARP recognize that AIC witness Stafford, who noted he is not an attorney, opposed the AG/AARP proposed adjustment, arguing that his interpretation of sections 16-108.5(c)(6) and 16-108.5(d)(1) of the Act do not permit the proposed adjustment to rate base. In essence, it appears to AG/AARP that AIC's view is that because the words “and ADIT” were not included in these referenced subsections of EIMA, no adjustment for ADIT on projected plant should be included in the formula rate revenue requirement calculation. AG/AARP submit, however, that Section 16-108.5(c) makes clear that the Commission shall evaluate formula rate revenue requirement determinations based on Article IX ratemaking principles. They note that under Section 16-108.5(d), the Commission “shall apply the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, in the hearing as it would apply in a hearing to review a filing for a general increase in rates under Article IX of this Act.”

AG/AARP note that the Commission has recognized this direction from the General Assembly in its application of Article IX ratemaking principles in the establishment of formula rate inception rates for both ComEd and, most recently, AIC. In its recent AIC formula rate Order of September 19, 2012 in Docket No. 12-0001, the Commission concluded:

> The Commission agrees with Staff and intervenors and finds that it would be appropriate to incorporate in this Order a portion of the relevant conclusion from the Order in Docket No. 11-0721:
>
>> . . . However, the statute is silent altogether with regard to ADIT and with regard to many other items that all agree must be included in, or deducted from, rates. If the Commission were to ignore ADIT

> on ComEd's plant investments, we would be ignoring basic accounting principles and appellate precedent. (See Ameren Illinois Co. v. Ill. Commerce Comm., 2012 IL. App. (4th) 100962 at 31, 2012 Ill. App. LEXIS 175 (4th Dist. 2012), determining, with regarding to an ADIT adjustment to Ameren's rate base, that Section 9-211 of the Public Utilities Act requires that rate base cannot exceed the investment value that a utility actually uses to provide utility services.).

(Order at 52)

AG/AARP opine that ADIT, a derivative adjustment that is caused primarily by plant additions, is a source of revenue for a utility. Because federal tax laws regarding 2011 allow businesses like AIC, currently, to depreciate plant additions at 100%, AG/AARP aver that AIC has use of funds now that it would not have otherwise normally have had access to without borrowing or other forms of financing. AG/AARP contend that, in effect, ignoring this windfall to a utility would allow that utility an interest-free loan at the ratepayers' expense for several months, and would artificially increase rates until the time when a final order in the 2011 reconciliation docket takes place. AG/AARP submit that it cannot have been the intention of the General Assembly, when enacting Section 16-108.5, to allow this statute to artificially raise rates for several months. In fact, AG/AARP note that this statute provides that the performance-based formula rate shall "reflect the utility's actual capital structure for the applicable year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law." (Section 16-108.5(c)(2)) AG/AARP contend that the facts that made this ADIT adjustment appropriate in both the Docket No. 11-0721 and Docket No. 12-0001 formula rate cases remain the same in this docket.

AG/AARP submit that Section 9-211 mandates that the Commission 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. AG/AARP argue that ignoring the effect of ADIT on the calculation and recognition of plant in rate base unlawfully increases the value of rate base with amounts that in fact are not used and useful in providing service to utility customers. (See Ameren Illinois Co. v. Ill. Commerce Comm., 2012 IL. App. (4th) 100962 at 5, (4th Dist. 2012) and Commonwealth Edison Co v. Ill. Commerce Comm., 405 Ill. App. 3d 389, 405 (2nd Dist. 2010))

AG/AARP note that Mr. Stafford asserts that Mr. Effron suggested that this adjustment is only needed because it reduces, not increases, the discrepancy between the rate base established in this proceeding and the rate base established in the subsequent reconciliation proceeding, with Mr. Stafford stating that "whether something is increasing or decreasing the rate base is irrelevant, and should not be the driving force to the argument." AG/AARP contend that this is a mischaracterization of Mr. Effron's testimony. They note that he did not suggest that this adjustment is "only needed" because it reduces the discrepancy. In addition to the legal reasons in support of this adjustment, AG/AARP aver that the adjustment is appropriate because it is directly related to the 2012 plant additions that AIC seeks to include in its formula rate base and reflects what will actually take place. AG/AARP aver that Mr. Stafford does not argue otherwise. As noted by Mr. Effron in his rebuttal testimony, saying that his proposed adjustment will likely reduce the discrepancy is not the same as saying it will reduce the rate base.

AG/AARP recommend that the Commission recognize in its calculation of the AIC rate base the ADIT associated with the projected plant additions included in the rate base. AG/AARP state that Mr. Effron calculated the increase in the balance of ADIT related to 2012 plant additions as $43,990,000, noting that the balance of ADIT deducted from plant in service in the determination of the delivery services rate base should be increased by this amount.

d. CUB Position

While AIC proposes to include 2012 projected plant additions in rates, CUB notes that AIC chooses to ignore the related substantial amounts of related 2012 ADIT for the difference between book and tax depreciation. Because the tax law provides for 50 percent bonus tax depreciation on 2012 qualifying assets, CUB submits that this is a significant omission that, if not adjusted, will overstate rate base for setting AIC's formula rates. CUB argues that this potential overstatement should be minimized now by reflecting the ADIT that is directly related to AIC's 2012 plant additions as an offset to rate base, similar to how accumulated depreciation directly related to the 2012 plant additions is reflected. By recognizing the 2012 ADIT impact from the 2012 plant additions in establishing AIC's formula rate plan revenue requirement at this time, CUB opines that this will help minimize the amount of over-collection that would likely result if this large impact is ignored now and only reflected subsequently in the 2012 reconciliation case.

CUB notes that AIC claims in its Initial Brief that Staff and intervenors' position amounts to an "additional update – to reflect ADIT generated by 2012 plant additions." Cub contends that this is not an "additional update" – it simply matches ADIT for 2010 bonus tax depreciation for the same time period as the 2012 projected plant additions, which are being included in rate base. CUB states that AIC further makes a statutory interpretation argument and argues that guarding against overstated rate base is of no consequence. While CUB contends that AIC does not appear to be concerned with over-collecting from ratepayers, the Commission should be. CUB urges the Commission to continue to follow appellate precedent and its own previous decisions, and match rate base to include ADIT for the same time period as plant additions.

CUB states that in Docket No. 11-0721, the Commission concluded that ignoring the ADIT directly related to jurisdictional plant increases would be ignoring accounting principles and appellate precedent. CUB opines that the Commission acknowledged that ADIT is a source of revenue for a utility, giving the utility use of funds now that it would not have otherwise normally had access to without financing, as the Commission stated:

> In effect, ignoring this windfall to ComEd would be to allow ComEd an interest-free loan at the ratepayers' expense for several months. It would artificially increase rates until the time when a final order in the 2011 reconciliation docket takes place. It cannot have been the intention of the General Assembly, when enacting Section 16-108.5, to allow this statute to artificially raise rates for several months. (Docket No. 11-0721 Order of May 29, 2012 at 59-60)

CUB notes that the Commission went on in Docket No. 11-0721, and incorporated into its Docket No. 12-0001 Order:

> ADIT, a derivative adjustment that is caused primarily by plant additions, is a source of revenue for a utility. Because federal tax laws regarding 2011 allow businesses like ComEd, currently, to depreciate plant additions at 100%, ComEd has use of funds now that it would not have otherwise normally have had access to without borrowing or other forms of financing. In effect, ignoring this windfall to ComEd would be to allow ComEd an interest-free loan at the ratepayers' expense for several months. It also would artificially increase rates until the time when a final order in the 2011 reconciliation docket takes place. It cannot have been the intention of the General Assembly, when enacting Section 16-108.5, to allow this statute to artificially raise rates for several months. (Docket No. 12-0001 Order of September 19, 2012 at 52-53)

CUB avers that each of the arguments articulated in the Order in Docket No. 11-0721 are applicable to the instant case and nothing in the factual record or law justifies a departure from the Commission's determination. Therefore, CUB recommends that the Commission adopt the proposed adjustment to ADIT and reduce rate base by $43.990 million. CUB also recommends that, consistent with its decisions in Docket Nos. 11-0721 and 12-0001, the Commission require AIC to reflect the ADIT related to estimated plant additions in the determination of formula rates.

e. Commission Conclusion

Staff, AG/AARP, and CUB all argue that the record evidence shows that AIC failed to recognize the growth in ADIT directly related to the 2012 projected plant additions. In the circumstances of this filing, AG/AARP witness Effron testifies that it is appropriate to include the effect of the ADIT generated by the 2012 plant additions in the calculation of the delivery services rate base. Mr. Effron suggests that the facts in this case show that the existence of 50% bonus depreciation in 2012 provides AIC with a tax deduction equal to one-half of the amount of additions to plant in service, which will lead to growth in the balance of ADIT in 2012 well in excess of the growth that would take place in the absence of the bonus depreciation. The Commission notes that Mr. Effron calculated the increase in the balance of ADIT related to 2012 plant additions as $43,990,000, as shown on his Schedule DJE-1.4, attached to AG/AARP Ex. 2.0. Mr.

Effron contends that in the circumstances of this case, this adjustment would tend to reduce, rather than increase, any discrepancy between the inception rate base in this case and the actual 2013 rate base. The Commission notes that Staff witness Chang and CUB witness Smith also proposed similar adjustments.

AIC contends that Sections 16-108.5(c)(6) and 16-108.5(d)(1) of the Act do not permit the proposed adjustment to rate base. AIC argues that because the words "and ADIT" were not included in these referenced subsections of EIMA, no adjustment for ADIT on projected plant should be included in the formula rate revenue requirement calculation.

The Commission believes that Section 16-108.5(c) makes it clear that the Commission shall evaluate formula rate revenue requirement determinations based on Article IX ratemaking principles. The Commission agrees with Staff, AG/AARP, and CUB that under Section 16-108.5(d) of the Act, the Commission "shall apply the same evidentiary standards, including, but not limited to, those concerning the prudence and reasonableness of the costs incurred by the utility, in the hearing as it would apply in a hearing to review a filing for a general increase in rates under Article IX of this Act." The Commission notes that it has recognized this direction from the General Assembly in its application of Article IX ratemaking principles in the establishment of formula rate inception rates for both ComEd and, most recently, AIC. In the recent AIC formula rate proceeding, in its Order of September 19, 2012, the Commission concluded:

> The Commission agrees with Staff and intervenors and finds that it would be appropriate to incorporate in this Order a portion of the relevant conclusion from the Order in Docket No. 11-0721:
>
> > . . . However, the statute is silent altogether with regard to ADIT and with regard to many other items that all agree must be included in, or deducted from, rates. If the Commission were to ignore ADIT on ComEd's plant investments, we would be ignoring basic accounting principles and appellate precedent. (See Ameren Illinois Co. v. Ill. Commerce Comm., 2012 IL. App. (4th) 100962 at 31, 2012 Ill. App. LEXIS 175 (4th Dist. 2012), determining, with regarding to an ADIT adjustment to Ameren's rate base, that Section 9-211 of the Public Utilities Act requires that rate base cannot exceed the investment value that a utility actually uses to provide utility services.).
> >
> > ADIT, a derivative adjustment that is caused primarily by plant additions, is a source of revenue for a utility. Because federal tax laws regarding 2011 allow businesses like ComEd, currently, to depreciate plant additions at 100%, ComEd has use of funds now that it would not have otherwise normally have had access to without borrowing or other forms of financing. In effect, ignoring this windfall to ComEd would be to allow ComEd an interest-free loan at

> the ratepayers' expense for several months. It also would artificially increase rates until the time when a final order in the 2011 reconciliation docket takes place. It cannot have been the intention of the General Assembly, when enacting Section 16-108.5, to allow this statute to artificially raise rates for several months. In fact, this statute provides that the performance-based formula rate shall:
>
> Reflect the utility's actual capital structure for the applicable year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law. (220 ILCS5/16-108.5(c)(2)).
> (Docket No. 11-0721, May 29, 2012 Order at 59-60)
>
> As the Commission found in Docket No. 11-0721, it is appropriate under the facts presented in this docket to update the ADIT balances as requested by Staff and the Intervenors. The Commission finds that the adjustment quantified by AG/AARP, $107,990,000, which amount it appears AIC did not contest as incorrect, is the appropriate adjustment to be adopted on this issue. (Order at 52-53)

The Commission finds that the arguments presented by AIC are not persuasive to distinguish this proceeding from Docket No. 11-0721 or Docket No. 12-0001. The facts that made this ADIT adjustment appropriate in both the ComEd and prior AIC formula rate cases remain the same in this docket. The Commission finds that the AG/AARP proposed recognition of the ADIT associated with the AIC-forecasted plant is appropriate for this proceeding and it is hereby adopted.

4. Accumulated Deferred Income Taxes – Step Up Basis Metro

a. AIC Position

AIC contends that AG/AARP's "step-up basis" recommendations are asymmetrical and should be rejected in this proceeding. AIC notes that AG/AARP recommend an additional rate-base reduction related to Account 190. According to AG/AARP witness Effron, in 2005, UE transferred certain tax depreciable assets to CIPS which transfers took place at the book value of the assets, which at the time was higher than the tax basis. AIC notes that AG/AARP assert that this transfer did not result in payment of any taxes and should not result in any increase to the net value of those assets included in AIC's rate base.

AIC argues that the error in this recommendation is that it assumes that the transfer would, in fact, result in any return of additional funds to AIC. AIC suggests that Mr. Effron has simply misunderstood the facts, as this transfer had zero effect on rate base. AIC notes that Staff witness Everson agreed that the evidence showed that the net ADIT included in rate base from this transfer was zero, therefore an adjustment is not necessary.

AIC submits that the problem seems to be that Mr. Effron focuses exclusively on one item, when that item was only one part of the accounting necessary to accommodate CIPS' purchase of UE's assets. When CIPS purchased the UE property, AIC asserts that it did so at net book value, so no book-tax difference and no ADIT resulted; however, since UE's records reflected the book value of the assets, depreciation reserve, and ADIT as they were on UE's records prior to the sale, CIPS set up a corresponding "contra-deferred tax liability" in Account 190 to account for the overall lack of book-tax difference intending that net deferred taxes at the date of the purchase on CIPS books were zero.

AIC opines that Mr. Effron is attempting to zero out an ADIT entry that has already been zeroed out, and his recommendation is in essence an attempt at double-counting. AIC notes that the step-up-basis item in Account 190—which Mr. Effron recommends offsetting by a reduction to rate base—is already offset by an equal amount of credit balance of ADIT in Account 282. AIC argues that making AG/AARP's reduction would not correct any error; it would commit one, by understating rate base.

AIC claims that Mr. Effron's own reference to the journal entry to record the transfer, which he points out shows that offsetting entries were made to Account 411, confirms the error, as there is not just one entry. As AIC witness Stafford explained, Mr. Effron did not consider the other journal entries presented in the response, and that response clearly shows that there were other entries associated with the metro transfer—not just to Accounts 190 and 411, but to Accounts 282 and 410 as well. AIC states that the effect of these entries, on a combined basis, show the amounts recorded to Account 190 were exactly offset by amounts recorded to Account 282. Therefore, the net ADIT effect, was zero. If AG/AARP will insist on reversing the entries to Account 190, then AIC suggests that the contemporaneous, offsetting entries must be reversed as well. While it might serve AG/AARP's ends to undo only half of the accounting related to this transfer, AIC notes that such asymmetry would be inappropriate and unfair and must be rejected.

AIC notes that Mr. Effron offered no response to these issues in his rebuttal testimony, but rather simply reiterated his previously stated position on this issue. AIC avers that this simply ignores the fact that the only challenged entry has already been zeroed out, therefore this proposed adjustment is unfounded.

b. Staff Position

Staff recommends that the Commission accept AIC's position that no adjustment to ADIT related to CIPS' purchase of certain assets from UE, referred to as "Metro East," is necessary in this proceeding. Staff agrees with AIC's assessment of the issue, noting that this issue was addressed in Docket No. 12-0001 and in that case, the Commission found that no adjustment was necessary. (See Docket No. 12-0001, September 19, 2012 Order at 69)

Staff notes that AG/AARP proposes an adjustment to ADIT related to CIPS' purchase of certain depreciable assets in the Metro East service area. Staff opines that AG/AARP posits that CIPS "stepped up" the tax basis of the assets to their book value which eliminated the deferred tax impact, thus the ADIT should follow the assets, without any offset. Staff states that AIC's response is that there was no net ADIT balance on the books at the time of the purchase of the property by CIPS and that the purchase was at an amount equal to UE's net book value of the assets. Thus, AIC claims that for book purposes the accounting entries reflected the book value of the assets, depreciation reserve, and ADIT as they were on UE's records prior to the sale. Staff agrees with AIC that no adjustment to ADIT is necessary since the record evidence is consistent with that provided in Docket No. 12-0001.

c. AG/AARP Position

AG/AARP state that the balance of ADIT related to "tax depreciation step-up basis Metro" represents certain tax depreciable assets to AIC companies back in 2005, when UE transferred certain tax depreciable assets to CIPS. AG/AARP claim that the transfer took place at the book value of the assets, which at the time of the transfer was higher than the tax basis. Because the transfer of the assets was between affiliated members of a consolidated tax return, there was no gain for tax purposes at the time of the transfer, however, CIPS "stepped up" the tax basis of the assets to their book value at the time of the transfer. AG/AARP note that with the book basis equal to the tax basis, there would be no net deferred taxes, and CIPS recorded a deferred tax asset that offset the related accumulated deferred taxes at the time of the asset transfer.

AG/AARP note that in response to Staff DR DLH 12.01 in Docket No. 12-0001, AIC provided the journal entry to record the transfer of the Metro assets from UE to CIPS, which shows the offsetting entries to Account 190 were credits to Account 411. AG/AARP state that Account 411 is an income statement account (credits to deferred income tax expense), thus, what AIC did at the time of the transfer of the Metro assets was to book offsetting entries to deferred tax assets and to income, in the form of a credit to deferred income tax expense. AG/AARP claim that AIC is now seeking to include what remains of the deferred tax assets booked at that time in rate base, just as it did in Docket No. 12-0001.

AG/AARP witness Effron testifies that the balance of ADIT related to "tax depreciation step-up basis Metro" is not properly includable in AIC's rate base. Under AIC's proposed ratemaking treatment, the net rate base value of the assets would be higher in the hands of CIPS than the net rate base value of the assets was in the hands of the affiliate from whom the assets were purchased, and this would clearly be inappropriate. Mr. Effron explains that the transfer of the assets from UE to CIPS at book value did not result in any payment of taxes at the time of the transfer, and this transfer of property from one regulated utility to another should not result in any increase to the net value of those assets included in AIC's rate base. For ratemaking purposes, AG/AARP contend that the ADIT associated with the assets at the time of the transfer should follow the assets, without any offset, and the deferred tax debit balance is, in effect, the other side of a gain booked at the time of the asset transfer. AIC should not have booked a gain on the transfer of assets between affiliates, and customers should certainly not be required to pay a return on an asset that was recorded in association with that gain. AG/AARP aver that elimination of the state and federal deferred ADIT on "tax depreciation step-up basis Metro" reduces AIC's jurisdictional rate base by $6,263,000, as shown in AG/AARP Ex. 2.1, Schedule DJE-1.1.

AG/AARP note that the Commission rejected a similar adjustment proposed by Mr. Effron in AIC's first formula rate case, however, they believe the Commission should re-visit that finding in light of the evidence in this docket. AIC, for example, argues that the net ADIT for this item included in the AIC rate base is zero -- that the debit balance of ADIT in Account 190 is offset by an equal amount of credit balance of ADIT in Account 282. AG/AARP claim that this response misses the point of Mr. Effron's proposed adjustment, as the fact is that there were related ADIT on the books of UE at the time of the transfer to UE. For ratemaking purposes, AG/AARP argue that that ADIT balance should follow the assets, without any entry to Account 190 to offset the credit balance of ADIT. If this is approach is not taken, AG/AARP argue that the net rate base value of the assets would be higher in the hands of CIPS than the net rate base value of the assets was in the hands of the affiliate from whom the assets were purchased, and this would clearly be inappropriate. AG/AARP submit that the issue here is not what is presently on AIC's books, but rather whether what is on AIC's books is appropriate for ratemaking.

d. CUB Position

CUB supports the adjustment proposed by AG/AARP witness Effron related to "tax depreciation Step-Up Basis Metro." CUB notes that this ADIT balance is the result of the 2005 transfer of UE tax depreciable assets to CIPS; a transfer that CUB states did not result in any payment of taxes at the time of the transfer, and which did not result in any increase to the net value of those assets included in AIC's rate base. CUB notes that there were related ADIT on the books of UE at the time of the sale. For ratemaking purposes, CUB argues that the ADIT associated with the assets at the time of the transfer should follow the assets, without any offset. If there is no entry to Account 190 to offset the credit balance of ADIT, CUB opines that the net rate base value of the assets would be higher in the hands of CIPS than the net rate base value of the assets in the hands of the affiliate from whom the assets were purchased—clearly an inappropriate result. CUB recommends that the Commission adopt the AG/AARP adjustment of $6.263 million.

e. Commission Conclusion

The Commission notes that each party contesting this issue has maintained the position they held in Docket No. 12-0001. AIC contends that it properly accounted for the item in question, with which Staff agrees. AG/AARP, supported by CUB, argue that an additional adjustment is necessary to properly account for the transfer, and recommend that a rate base adjustment of $6.263 million should be adopted by the

Commission. The Commission further notes that this issue was decided in favor of AIC and Staff in Docket No. 12-0001.

The Commission is not persuaded by AG/AARP and CUB that there is a need for an additional accounting adjustment with regard to the acquisition of assets by CIPS from UE. The Commission agrees with AIC and Staff that to adopt AG/AARP's proposed adjustment for a reduction to Account 190 without corresponding adjustments to other accounts would understate rate base. Moreover, the Commission finds that AG/AARP and CUB have offered no reason to treat this issue differently in this case than it was treated in Docket No. 12-0001. Therefore, the Commission rejects AG/AARP's recommendation, and finds that based on the evidence presented in this proceeding, AIC has properly accounted for this issue, and there is no need for any additional adjustment.

5. Cash Working Capital

The Commission notes that AIC has included $13,607,000 for CWC in rate base in this proceeding. AIC's CWC calculation is based upon a lead/lag methodology developed in the testimony and supporting workpapers of AIC witness Heintz in Docket No. 12-0001. AIC states that those workpapers were included in AIC's filing in support of Schedule B-8 of the Part 285 filing schedules. In Docket No. 12-0001, AIC proposed to update the lead/lag analysis every three years for purposes of the formula rate. As a result, for this initial update filing, only an update of the revenue and expenses for the applicable calendar year, 2011, has been reflected in the determination of CWC. Various parties to this proceeding contest certain aspects of AIC's CWC calculation.

a. Pass Through Taxes Revenue Lag

i. AIC Position

AIC recognizes that the Commission set the revenue lag for pass through taxes at zero days in Docket No. 12-0001; however, AIC maintains its position on this issue in this proceeding. AIC proposes a revenue lag of 34.54 days for pass-through taxes, specifically, Energy Assistance Charges ("EAC") and Municipal Utility Tax ("MUT"), in its CWC calculation. AIC submits that this reflects the actual treatment of pass-through tax collections and remittances by AIC, although Staff witness Kahle and AG witness Brosch recommend that the revenue lag period associated with pass-through taxes included in AIC's CWC determination be set to zero days.

AIC contends that the crux of the dispute with respect to the EAC is whether AIC's CWC calculation should reflect the amount of time that AIC could hold pass-through taxes under the statutory remittance requirement, or the amount of time that AIC actually does hold the pass through taxes before remitting. AIC notes that its CWC amounts reflect the latter, which it indicates is consistent with the Commission's Order in Docket No. 11-0282, which expressly rejected Staff's proposal to use zero lag days for EAC in that proceeding. AIC states that Mr. Kahle acknowledged at hearing that, under AIC's actual remittance practice, AIC only has access to the EAC funds for four days and the MUT funds for only 14 days. AIC submits that the CWC calculation should reflect this, and the Commission should continue to utilize AIC's actual remittance practice, as it did in Docket No. 11-0282.

AIC contends that Staff's position chooses consistency with the order in Docket No. 11-0721 over consistency with the Commission's order in AIC's gas rate case, Docket No. 11-0282—an order for the same utility that has the same pass-through tax payment practices at issue in this case. AIC claims that the fact that the order in Docket No. 11-0282 was for AIC's gas business does not negate its applicability to AIC's electric business. AIC notes that Mr. Kahle conceded at hearing that the facts at issue are the same between this case and the gas case. AIC states that its gas and electric operations are both part of the same utility, and the taxes in question are billed, collected, and remitted to the taxing authorities in exactly the same manner for AIC's gas and electric business. AIC also claims that it has not modified its EAC remittance schedule since the Commission's decision in Docket No. 11-0282, and it is illogical for the Commission to disregard its decision in Docket No. 11-0282.

Moreover, as AIC witness Heintz explained, not all utilities treat pass-through taxes in a similar manner. AIC complains that Staff does not examine differences in remittance practices between AIC and ComEd. For example, AIC states that the record in this case makes clear that AIC would incur time and expense to change its remittance timing for the EAC, while there is no evidence that ComEd would incur similar time and expense to change its remittance practices.

AIC urges the Commission to reject the parties' proposed zero days revenue lag attributed to pass-through taxes in favor of the 34.54 revenue lag supported by AIC. AIC maintains that its analysis accurately reflects the actual timing of the billing, collection, processing, and bank float associated with customers' payments during the test year.

ii. Staff Position

Staff notes that the Commission found in Docket No. 12-0001 that the revenue lag for pass-through taxes should be zero. (September 19, 2012 Order at 14) Staff recommends that the Commission disallow a revenue lag for pass-through taxes in this case as well. Staff states that CWC is the amount of funds needed from investors to fund day-to-day utility operations and utilities are allowed to earn a return on those funds; however, some funds used for daily operations are actually provided by ratepayers and no return should be provided on those funds. To ensure no return is earned on customer-provided funds, Staff notes that these dollars are subtracted from CWC, with pass-through taxes being an example of funds provided by ratepayers. Staff states that utilities are required to collect the pass-through taxes from ratepayers and remit the pass-through taxes to the taxing body within 20 to 30 days after collection from ratepayers. Because pass-through taxes are funded by ratepayers, Staff argues that the utility has no investment in pass-through taxes on which ratepayers should pay a return through increased CWC.

Staff submits that its position is also consistent with the Commission's Orders in both AIC's most recent electric rate case (Docket Nos. 09-0306/0307/0308, April 29, 2010 Order at 54) and the ComEd formula rate case, the only other formula rate case with a Order that has come before the Commission. (Docket No. 11-0721, May 29, 2012 Order at 45) Staff notes that while AIC and ComEd do not operate in the same service territories, they both operate under the same State statutes for EAC. Staff opines that it would be unreasonable for a formula rate to incorporate a different lag for the same tax in a formula that should, for the most part, be consistent.

iii. AG/AARP Position

AG/AARP propose to set to zero the revenue lag days associated with pass-through charges for EAC, MUT, and Gross Receipts Taxes. AG/AARP argue this is necessary because pass-through taxes are completely ratepayer funded, and they have no CWC impact because the inflows and outflows earmarked for these taxes occur after taxable revenues have been collected by the utility. Thus, AG/AARP state that no utility cash flow issue arises for the utility, since the taxes are not required to be paid until after the customer revenues that cover this pass-through expense are collected.

AG/AARP note that the Commission has repeatedly concurred with the rationale that supports the AG/AARP CWC adjustment, and the facts in this docket should not alter that conclusion. In Docket No. 12-0001, the Commission concluded:

> The Commission agrees with Staff and the other parties that the proper revenue lag associated with these items should be zero days. The Commission recognizes that in Docket No. 11-0282 it had granted AIC revenue lag days in its CWC calculation for these items, and indicated that it would revisit this issue if AIC changed the manner in which it handled these items. The Commission also recognizes that in ComEd's formula rate case, in addressing this same issue, the revenue lag days were set at zero, despite ComEd's reliance on Docket No. 11-0282. The Commission believes that consistency between the relevant utilities in the smart grid dockets is an important consideration to take into account. The Commission therefore finds that the appropriate revenue lag days for this issue should be zero, as recommended by Staff, IIEC, AG/AARP, and CUB. (September 19, 2012 Order at 14)

The citation above is to the Commission's May 29, 2012 Order in the ComEd formula rate case, Docket No. 11-0721. Likewise, in Docket No. 10-0467, the Commission found that pass-through taxes should not be assigned a revenue lag because they are payable after revenues are collected from customers, stating in the Order:

> The Commission agrees with Staff's interpretation as to the EAC/REC and GRT/MUT tax issues. For the EAC/REC tax, the utility shall remit all moneys received as payment to the Illinois Department of Revenue by the 20th day of the month following the month of collection. Under the GRT/MUT tax, this ordinance requires ComEd to file a monthly tax return to accompany the remittance of such taxes, due by the last day of the month following the month during which such tax is collected. Both the statute and ordinance requires ComEd to remit these pass-through taxes after they have been collected from customers. ComEd stated in its briefs that the Company correctly pays these taxes in the month following activity that occurs in a prior "tax liability" month. The Commission concludes that the CWC calculation for GRT/MUT pass-through taxes should reflect zero revenue lag days and 44.21 expense lead days and zero revenue lag days and 35.21 expense lead days for EAC/REC pass-through taxes as supported by Staff. (May 24, 2011 Order at 48)

AG/AARP note that in its Initial Brief, AIC argues that the "crux of the dispute with respect to the EAC is whether AIC's cash working calculation should reflect the amount of time that AIC could hold pass through taxes under the statutory remittance requirement or the amount of time that AIC actually does hold the pass through taxes before remitting." (AIC Initial Brief at 16) AIC suggests that its CWC amounts reflect the latter.

AG/AARP state, however, that the Commission has repeatedly rejected that argument, recognizing that ratepayers should not incur higher rates simply because AIC chooses to assume that its responsibility to pay these taxes exists when service is rendered rather than when revenues are actually collected. Instead, pass-through taxes are not included in AIC's revenues but instead represent funds provided by ratepayers. (See Docket No. 12-0001 September 19, 2012 Order at 14; Docket No. 11-0721, May 29, 2012 Order at 45-46; Docket No. 10-0467, May 24, 2011 Order at 48) AG/AARP state that the Commission found that pass-through taxes should not be assigned a revenue lag because they are payable after revenues are collected from customers, and the facts have not changed in this docket. AG/AARP urge the Commission to adopt Mr. Brosch's well-reasoned adjustment to the AIC CWC calculation to reflect a zero revenue lag attributable to the pass-through taxes at issue.

AG/AARP assert that the facts regarding the timing of statutory tax due dates and customer financing of these amounts have not changed in this docket, noting that the rationale supporting this adjustment was also debated in Docket No. 12-0001. AG/AARP opine that AIC has presented no evidence to suggest that the required statutory filing date has changed, with AIC witness Heintz testifying that he knows of no change in state or federal tax law or regulation that has occurred recently that would modify the terms under which the EAC or MUT taxes are assessed and paid. AG/AARP note that Mr. Heintz further testifies that AIC's payment of those taxes occurred after the receipt of the revenues from ratepayers. AG/AARP argue that the evidence fully supports Mr. Brosch's adjustment related to pass-through taxes to the CWC calculation, as shown in AG/AARP Ex. 3.1 at 2.

iv. Commission Conclusion

The Commission notes that the rationale regarding this proposed adjustment by Staff and AG/AARP was fully debated in Docket No. 12-0001 and the adjustment proposed by Staff and AG/AARP was adopted in that proceeding. The Commission believes that the facts regarding the timing of statutory tax due dates and customer financing of these amounts have not changed in this docket. Staff and AG/AARP contend that the evidence shows that pass-through taxes are (1) completely ratepayer funded, and (2) have no CWC impact because the inflows and outflows earmarked for these taxes occur after taxable revenues have been collected by the utility. Staff and AG/AARP contend that no utility cash flow issue arises for the utility, since the taxes are not required to be paid until after the customer revenues that cover this pass-through expense are collected.

AIC argues that in its last gas rate case, Docket No. 11-0282, the Commission noted it would revisit the issue if AIC alters its EAC remittance schedule. AIC contends that the evidence presented in this proceeding shows that AIC has not altered its remittance schedule. AIC submits that its analysis accurately reflects the actual timing of the billing, collection, processing and bank float associated with customers' payments during the test year, therefore the Commission should reject the proposed zero days revenue lag attributed to pass-through taxes in favor of the 34.54 revenue lag supported by AIC.

As Staff and AG/AARP point out, the Commission has repeatedly concurred with the rationale that supports the proposed CWC adjustment, and the facts in this docket do not support a different conclusion. In Docket No. 12-0001, the Commission concluded:

> The Commission agrees with Staff and the other parties that the proper revenue lag associated with these items should be zero days. The Commission recognizes that in Docket No. 11-0282 it had granted AIC revenue lag days in its CWC calculation for these items, and indicated that it would revisit this issue if AIC changed the manner in which it handled these items. The Commission also recognizes that in ComEd's formula rate case, in addressing this same issue, the revenue lag days were set at zero, despite ComEd's reliance on Docket No. 11-0282. The Commission believes that consistency between the relevant utilities in the smart grid dockets is an important consideration to take into account. The Commission therefore finds that the appropriate revenue lag days for this issue should be zero, as recommended by Staff, IIEC, AG/AARP, and CUB. (September 19, 2012 Order at 14)

The Commission also agrees with Staff that while AIC and ComEd do not operate in the same service territories, they both operate under the same State statutes for EAC. The Commission agrees that it would be unreasonable for a formula rate to incorporate a different lag for the same tax in a formula that should, for the most part, be consistent.

The Commission finds that the evidence presented in this proceeding supports the recommendations of Staff and AG/AARP to adopt the use of zero lag days for pass-through taxes. The Commission finds the proposal of Staff and AG/AARP to be reasonable based on the evidence presented, and it is therefore adopted for this proceeding.

b. Revenue Collection Lag

i. AIC Position

AIC notes that the Order in Docket No. 12-0001 rejected AG/AARP's recommendation to not utilize AIC's actual aged receivable methodology, and suggests that the lead lag values for this issue are identical in this proceeding as those presented (and approved by the Commission) in Docket No. 12-0001, only the dollar values have changed. While AG/AARP witness Brosch continues to criticize AIC's analysis because of its "unsubstantiated assumptions," and "assumed, rather than proven, dates when customers, on average, actually remit payments of their utility bills," as the Commission found in Docket No. 12-0001, AIC has used a collection lag methodology, based on actual data, repeatedly sanctioned by the Commission and similar to that employed by other major Illinois utilities. AIC notes that in its Order in Docket No. 11-0721, the Commission approved ComEd's use of a midpoint methodology in its initial formula rate proceeding. (May 29, 2012 Order at 41-42) AIC states that the Commission found AIC had adequately considered the issue presented in calculating the collection lag in Docket No. 12-0001, and AIC recommends that the Commission find so again in this proceeding, and should reject AG/AARP's recommendation on this issue.

While Mr. Brosch continues to propose that in future rate proceedings, AIC should be required to calculate the collections lag based upon what he deems to be generally accepted methods: 1) a study of the timing of customers' actual remittances; or 2) daily accounts receivable turnover; AIC contends that these proposals should be rejected as unnecessary. AIC first notes that a customer remittance analysis, which examines the timing of actual payments made by customers to calculate the collections lag, should not be used. While this analysis would seem to be reasonable; AIC contends that it would exclude any customer bills that have not been paid, therefore, the analysis is biased towards customers that pay their bills on time and ignores (or penalizes AIC for) those customers that have outstanding balances. AIC also opines that the additional studies proposed by Mr. Brosch would result in additional cost, and Mr. Brosch has failed to demonstrate that undertaking such studies would produce a materially better result or would justify the time and expense to develop the data needed to perform the study. AIC notes that the Commission also rejected Mr. Brosch's proposal in Docket No. 12-0001, indicating that his method "could be biased toward certain customers and unduly penalize AIC, without any evidence that the additional cost would produce a better result for the Commission's consideration." (September 19, 2012 Order at 25) AIC asserts this it has calculated its proposed collection lag using actual data, and a methodology approved by the Commission, and Mr. Brosch's proposals should be rejected.

ii. Staff Position

Staff supports the collection lag days as proposed by AIC. Staff recommends that the Commission not set revenue lag at 21 days as proposed by AG/AARP witness Brosch. Staff notes that Section 735.160(a)(2) of the Illinois Administrative Code (83 Ill. Adm. Code 735.160(a)(2)) establishes that the number of days between the date the utility customer receives the bill and the due date for payment of the bill must not be less than 21 days. Staff complains that this rule, however, does not reflect the actual collection lag which has been calculated by AIC in a lead/lag study in a manner consistently accepted by the Commission.

iii. AG/AARP Position

AG/AARP continue to support Mr. Brosch's proposed adjustment to the Revenue Collection Lag component of the AIC CWC calculation. AG/AARP state that the evidence in this docket shows that AIC continues to rely upon a CWC study that includes no specific analysis of the timing of customer accounts receivables – a critical component of any evaluation of the timing of AIC remittances and collection of revenues – despite AIC's concurrence that the revenue collection lag is one of the most important components of the CWC study.

The Commission's Order in Docket No. 12-0001 followed the precedent of the Commission's decision in Docket No. 11-0721 in rejecting the AG/AARP Revenue Collection Lag adjustment. However, AG/AARP complain that reliance on the Orders in those dockets as a basis for rejecting Mr. Brosch's adjustment to the AIC Revenue Collection Lag is misplaced. AG/AARP claim that Mr. Brosch's proposed adjustment in this docket incorporates the very same "grace period" insertion – which are based on Commission rules requiring that bill due dates for residential service cannot be less than 21 days after the delivery date on the bill -- that was adopted by the Commission in the ComEd docket.

While AIC claims that the Commission's decision in Docket No. 11-0721, which cites a prior Commission decision in Docket No. 10-0467, is reason enough for dismissing Mr. Brosch's proposed adjustment, contrary to AIC's representations, AG/AARP claim that the Commission's decisions in Docket Nos. 10-0467 and 11-0721 instead support adoption of Mr. Brosch's Revenue Collection Lag adjustment.

AG/AARP claim that the record evidence supports Mr. Brosch's Revenue Collection Lag adjustment, noting that AIC witness Heintz presented no new evaluation of AIC's cash flows, instead relying on the study that was the basis for AIC's CWC calculation in Docket No. 12-0001. AG/AARP state that AIC's approach grouped the account receivables balances into aging buckets including current, 30 to 60 days, 60 to 90 days, and over 90 days bucket, and for each of the first three buckets of receivables, a midpoint is used in the calculation, purportedly to represent an undetermined average payment date for accounts receivables. AG/AARP claim that the midpoint methodology assumes that customer payments occur ratably over the course of a month, which is to say that as many customers are expected to pay their bills before the midpoint period as will pay after the midpoint period. AG/AARP note that these assumptions are made despite the fact that neither Mr. Heintz nor any AIC employee conducted any kind of analysis to determine if the midpoint is, in fact, the average remittance day for each of the 30-day aging buckets for the accounts receivables. AG/AARP claim that this midpoint assumption practice continues despite the fact that if the actual average payment date is even a single day off of the midpoint; the dollar effect is approximately over $1 million per day off the midpoint.

In addition to the use of this unsupported, random methodology, AG/AARP claim that the evidence shows that AIC failed to incorporate any grace period in the calculation of the Revenue Collection Lag, contrary to the ComEd methodology adopted repeatedly by the Commission. In order to inject a measure of conservatism to this random, midpoint assumption methodology, Mr. Brosch inserted the same grace period customer remittance assumptions that were previously adopted by ComEd and that were approved by the Commission in Docket Nos. 10-0467 and 11-0721. AG/AARP aver that this grace period assumption is consistent with the Commission's requirement under Commission rules that bill due dates for residential service cannot be less than 21 days after the delivery date on the bill. (83 Ill. Adm. Code 280.90) AG/AARP note that no late payment charges can be assessed until utility service becomes past due under these limitations. AG/AARP assert that these same due date grace periods that are specified in the Commission's rules and previously adopted for ComEd in Docket Nos. 10-0467 and 11-0721, should be incorporated into the Revenue Collection Lag component of the AIC CWC calculation. AG/AARP state that incorporation of this adjustment in the AIC CWC calculation reduces the Revenue Collection Lag Days number from 49.75 days to 41.12 days, as shown on AG Ex. 3.1, page 2, and it should be adopted by the Commission.

iv. Commission Conclusion

The Commission notes that AIC has proposed a revenue collection lag of 30.67 days, indicating that it calculated the collection lag using an analysis of actual aged receivables data, which was then adjusted to reflect potentially uncollectible receivables. AIC contends that the method it used in this docket is the same method approved by the Commission in Docket Nos. 09-0306 et al. (Cons.) and 12-0001. AIC objects to the methodology proposed by AG/AARP, noting that the record in this proceeding provides no evidence that the adjustment proposed by ComEd in its docket has any applicability to AIC or its customers' payment patterns. AIC also recommends that the Commission not accept AG/AARP's recommendation for future proceedings, contending that the analysis would be biased toward customers that pay on time and either ignores or penalizes AIC for customers that have outstanding balances. AIC also suggests that AG/AARP's proposal would entail additional costs, without any showing that it would produce a materially better result. The Commission also notes that Staff supports AIC's calculation on this issue.

AG/AARP, however, complain that AIC is assuming, rather than proving, the dates on which customers actually paid their bills, therefore AG/AARP suggest that AIC's calculation is lacking. AG/AARP propose that AIC’s lead lag study be modified to incorporate revision of AIC’s estimated revenue collection lag to insert reasonable grace period assumptions, as were used in ComEd’s calculations approved by the Commission in Docket No. 10-0467. AG/AARP contend that the impact of revising AIC's collection lag and overall revenue lag for the effects of billing grace periods, using ComEd's methodology, is significant. AG/AARP state that the collection lag of 30.67 days in AIC's study would be reduced from 30.67 to 22.04 using the ComEd assumptions. AG/AARP contend this would result in a revised overall revenue lag of 41.12 days, as compared to AIC's proposed 49.75 day revenue lag. AG/AARP also recommend that the Commission order AIC to either conduct a daily accounts receivable turnover analysis or use a statistically valid sample of customers' actual remittances in future filings. The Commission notes that CUB supports AG/AARP's recommendation.

The Commission believes that the evidence presented shows that AIC has appropriately calculated the revenue collection lag; therefore it will be adopted for this proceeding. The Commission agrees with AIC that it has adequately considered the issues presented in calculating the collection lag, and the Commission notes that the method used is the same as that accepted by the Commission in Docket Nos. 09-0306 et al. (cons.) and 12-0001. The Commission also will decline to accept the recommendation of AG/AARP for AIC in future proceedings to either conduct a daily accounts receivable turnover analysis or use a statistically valid sample of customers' actual remittances in future filings. The Commission will also decline to accept AG/AARP's recommendation to incorporate a grace period into the calculation of CWC on this issue. The Commission agrees with AIC that the proposed method could be biased toward certain customers and unduly penalize AIC, without any evidence that the additional cost would produce a better result for the Commission's consideration.

c. Income Tax Expense Lead and Lag

i. AIC Position

AIC notes that the Order in Docket No. 12-0001 found that AIC’s utilization of statutory tax rates and payment dates when determining CWC is consistent with Commission practice of not considering current and deferred income taxes separately for the purposes of calculating CWC. (September 19, 2012 Order at 29) AIC states that the Commission also noted it has a long-standing practice of setting AIC’s income tax expense based on statutory tax rates and payment dates when calculating income tax expense for revenue requirement purposes. As such, AIC does not distinguish between current and deferred tax expense for CWC purposes, nor does AIC include permanent tax differences in its income tax expense calculation.

AIC observes that AG/AARP witness Brosch recommends revenue lag and expense lead days be set at zero for income taxes in the CWC analysis. AG/AARP note that the basis for his recommendation is that AIC's 2011 income taxes currently payable are substantially negative and more than 100% of AIC's 2011 income taxes are actually non-cash deferred income taxes, for which there is no current period cash flow that could contribute to CWC.

AIC suggests that not only is Mr. Brosch's recommendation inconsistent with Commission practice, his proposal would also disrupt the balance between the ratemaking cost of service and the inputs to the CWC calculation. AIC notes that the differentiation between current and deferred income tax expenses can swing between rate filings, reflecting then current tax laws; and suggests that the use of statutory tax rates and payment dates maintains a consistent treatment of income tax expense for ratemaking purposes and avoids such swings in balances. AIC avers that both the Commission and Staff have accepted AIC's calculation of income tax expense based upon the statutory tax rates and payment dates in prior rate proceedings, including AIC's initial formula rate filing.

ii. Staff Position

Staff agrees with AIC that its suggested treatment of deferred income taxes for CWC is consistent with Commission practice. Staff recommends that the Commission not accept the proposal of AG/AARP witness Brosch to set income tax lead and lag days to zero, noting that the Commission has a long standing practice of not considering current and deferred income taxes separately.

iii. AG/AARP Position

AG/AARP note that Mr. Brosch's restatement of AIC's CWC calculation includes removal of deferred state and federal income tax expense, as these amounts – by definition -- represent non-cash items that do not belong in AIC's CWC presentation. AG/AARP contend that it is appropriate to remove these amounts from the CWC calculation because CWC involves the study of cash flows and deferred income taxes involve no cash flows because they are "deferred" rather than being paid to taxing authorities, and there can be no payment lead days or CWC impact if there is no payment. While AIC responds that it has a long-standing practice of employing statutory tax rates and payment dates when calculating its income tax expense for revenue requirement purposes, therefore AIC does not distinguish between current and deferred tax expense; AG/AARP argue that this misses the point with regard to cash flows. As explained by AG/AARP witness Brosch, there is a difference between "calculating income tax expense" and CWC associated with income taxes. AG/AARP aver that the distinction is that AIC's use of statutory tax rates to calculate income tax expense does not create a cash payment, noting that all of AIC's calculated income tax expenses are deferred on AIC's balance sheet, adding to AIC's ADIT balances instead of being remitted to taxing authorities.

AG/AARP aver that the notion that deferred taxes represent non-cash expenses (and therefore should be omitted from CWC calculations) is not an anomaly, noting that AIC Schedule C-4, page 6, which details AIC's recorded currently payable federal income taxes, shows negative amounts of currently payable cash income taxes in each of the years 2008 through 2011. Likewise, AG/AARP state that AIC's recorded currently payable state income taxes ("SIT") have been negative in all these historical years except for 2009.

While AIC contends that the differentiation between current and deferred income tax expenses can swing between rate cases, reflecting then current tax laws, and argue that the use of statutory tax rates and payment dates maintains a consistent treatment of income tax expense for ratemaking purposes; AG/AARP opine that history does not support this notion of "swings" between rate cases, and certainly does not justify including non-cash expenses in a CWC presentation. AG/AARP aver that AIC's Schedule C-4 indicates remarkable consistency in paying no current taxes historically, while recording only deferred income tax expenses, and there are no apparent "swings" toward currently payable income taxes expected in the near future. AG/AARP note that Ameren has announced in its SEC Form 10Q filings that its NOL tax carry forwards should prevent it from actually paying federal income taxes until 2014.

AG/AARP argue that even if AIC's concern about future "swings" in the mix of current versus deferred income tax expense amounts is valid, formula ratemaking provides an opportunity to annually update the relevant calculations to revise total income tax expense for all of the impacts. AG/AARP suggest that there simply is no valid basis for including deferred taxes that have not and will not be paid out to the state and federal governments in the near future as a remittance in a CWC calculation. In addition, AG/AARP assert that it is always necessary to isolate and exclude non-cash expenses such as depreciation expense, amortization expense, and deferred income taxes when calculating CWC, with which Mr. Heintz agreed. AG/AARP contend that only cash expenses belong in lead lag studies, and deferred income taxes are not cash expenses.

AG/AARP opine that Commission precedent likewise favors adoption of the AG/AARP recommendation on this point, noting that ComEd's income tax posture is similar to AIC, where large income tax deductions have caused more than 100% of ratemaking income tax expense to be in the form of deferred, rather than currently payable, income taxes. In its Order in the ComEd formula rate proceeding, Docket No. 11-0721, AG/AARP note that the Commission approved inclusion of the negative amount of currently payable SIT and Federal Income Tax expense, at lines 26 and 27 of the CWC calculation, and reduced the "Total Receipts" subject to the revenue lag at lines 1 and 6 for such negative currently payable income tax outlays, and no amounts of deferred state or federal income taxes were included.

AG/AARP submit that AIC itself recognizes that deferred income taxes are non-cash expenses in its published financial statement, noting that in Ameren's Consolidated Statement of Cash Flows, deferred income taxes are recognized as an adjustment to reconcile net income to net cash provided by operating activities, because deferred income tax expenses are recorded as expenses but do not require cash outflows. AG/AARP aver that this acknowledgement of depreciation and deferred income taxes as non-cash expenses can also be observed in AIC's filed WPD-7, page 10, lines 4 and 2, where non-cash expenses such as Deferred Income Taxes and Depreciation/Amortization are added back to Net Income in order to determine "FUNDS FROM OPERATIONS."

AG/AARP argue that only "currently payable" income taxes involve any cash outflows that should be included in the lead lag study, and since AIC is not currently paying income taxes, and has calculated negative current income tax expenses in its rate filing, there should be no CWC impact from income taxes. AG/AARP suggest that this result is best accomplished by setting the lag values to zero, as shown in AG/AARP Ex. 3.1, page 2, line 18. Alternatively, AG/AARP do not object to the treatment applied by the Commission to ComEd's income tax posture which was comparable to Ameren's, in which the negative amount of currently payable income taxes are reflected in both the expense lead calculation and as a reduction to revenues that are subjected to the revenue lag.

iv. Commission Conclusion

The Commission notes that on the issue of income tax lead and lag, AIC contends that it utilized statutory income tax rates and payment dates when determining CWC. AIC believes that this is consistent with Commission practice of not considering current and deferred income taxes separately when calculating CWC. AIC believes that AG/AARP's proposal to set the revenue lag and expense lead days at zero for income taxes because AIC's current income taxes are substantially negative, and more than 100% of AIC's 2011 income taxes are actually non-cash deferred income taxes, is not only inconsistent with Commission practice, but would disrupt the balance between the ratemaking cost of service and the inputs to the CWC calculation. The Commission notes that Staff recommends the Commission adopt AIC's position on this issue, as it is consistent with past Commission practice.

The Commission notes that AG/AARP recommend that the Commission set the revenue lag days and the expense lead days at zero, since AIC's adjusted income taxes currently payable are negative. AG/AARP contend that since more than 100% of AIC's test year income taxes are actually non-cash deferred income taxes, there is no current period cash flow that could contribute to CWC. AG/AARP state that the approach it recommends was the method adopted by the Commission in Docket No. 11-0721. CUB also recommends that the Commission set the revenue lag and expense lead values to zero due to AIC's 2011 adjusted income taxes being substantially negative, asserting that this is consistent with Docket No. 11-0721.

In response, AIC argues that in contrast to ComEd, AIC calculates income tax expenses based on statutory rates, while ComEd calculates its income tax expense based on actual rates. AIC asserts that as the two methodologies are not aligned, it would be inappropriate to impose the method in the ComEd docket on AIC.

The Commission finds that AIC, as supported by Staff, has proposed the appropriate method in this docket for determining the appropriate income tax lead and lag. The Commission agrees that it has a long-standing practice of not considering current and deferred income taxes separately. The Commission finds no evidence has been presented in this proceeding to cause it to vary from this treatment. The Commission recognizes that a different result was adopted in the ComEd docket, Docket No. 11-0721; however, the Commission recognized in its Docket No. 12-0001 Order that ComEd and AIC calculate income taxes using different methodologies. The Commission reiterates that should those methodologies align in the future, or new evidence be presented, the Commission will re-visit this issue in future proceedings.

VI. OPERATING EXPENSES

A. Uncontested Issues

1. Athletic Ticket/Event Expense

AIC voluntarily removed from the revenue requirement $127,000 associated with corporate sponsorships of athletic events. The total electric jurisdictional amount removed from the revenue requirement is $123,000. While Staff agrees with AIC's removal of this amount, it only reflects a portion of the total amount of AIC corporate sponsorships that Staff asserts should be disallowed for recovery, as discussed elsewhere in this Order. The Commission finds the agreed-to adjustment removing costs for athletic tickets and events appropriate and adopts it.

2. Regulatory Commission Expense - Docket No. 11-0279

Staff recommends disallowance of $2,000 in certain consultant charges (among others) included in AIC’s Regulatory Commission Expense incurred in connection with Docket No. 11-0279. AIC agrees not to pursue recovery of the cost. The Commission finds the adjustment appropriate and adopts it.

3. Edison Electric Institute Membership Dues Allocated to Lobbying

AG/AARP and Staff recommend an adjustment to remove from the revenue requirement the portion of AIC's Edison Electric Institute ("EEI") association dues allocable to lobbying activities. AIC agrees to the removal of $115,000 ($123,000 before jurisdictional allocations) as the portion of EEI dues associated with lobbying activities. In addition, AIC removed $59,000 ($64,000 before jurisdictional allocations) for the cost of labor for three employees with lobbying responsibilities. The Commission finds the adjustments appropriate and adopts them.

4. e-store Costs

Staff, AG/AARP, and CUB all propose an adjustment to remove $8,473 representing the electric portion of expenses associated with the Ameren online employee e-store that were allocated to AIC. AIC still considers the e-store costs to be a reasonable business expense for a large utility that is not intended to promote AIC's image. Based on the Commission's decision in Docket No. 12-0001, however, AIC now agrees with the proposed adjustment and has reflected the disallowance in the schedules attached to its Initial Brief as Appendix A. The Commission finds the adjustment appropriate and adopts it.

5. "Focused Energy. For Life." Costs

In response to disallowances CUB proposes, AIC agrees to remove $17,182 of costs associated with its campaign called "Focused Energy. For Life." ("FEFL"). While Staff agrees that this amount should be removed, it only reflects a portion of the entire cost of the campaign with which Staff takes issue. The remaining costs of this campaign are a contested issue discussed elsewhere in this Order. Furthermore, AIC agrees to remove an additional $4,983 of jurisdictional electric distribution costs for a CoreBrand, LLC ("CoreBrand") consultant that should not have been included in this case as a cost to ratepayers since the research initiative led by CoreBrand was aimed at determining a relationship to shareholder value. Staff agrees that this adjustment should be made. The Commission finds the adjustments appropriate and adopts them.

6. Employee Book Purchases

Staff proposes to disallow a specific purchase card ("P-Card") charge of $4,387 for copies of the book Strength & Compassion for AIC employees. Although AIC considers the purchase of these books to be a reasonable business expense, it agrees to remove the expense from the revenue requirement. The Commission finds the adjustment appropriate and adopts it.

7. Other Expenses

AIC voluntarily removed from the revenue requirement $31,609 representing the cost of nineteen items listed in AIC Ex. 14.3. The expenses include costs for holiday cards, a banking ad for Ameren Energy Management banking, a communication for Energy Resource Group, street pole banners, photography of the Callaway Nuclear Plant, an updated display at Wilmore Lodge at the Lake of the Ozarks, allocated administrative costs to relocate an employee for commercial related work, allocated administrative costs for community related communication and information messaging on renewables, the editing of a clean air educational video for the Energy Learning

Center, and other items. The Commission finds the adjustment appropriate and adopts it.

8. February 2011 Storm Event

AIC Ex. 1.1, Schedule FR B-1, line 31 identifies Other Deferred Charges in excess of $3.7 million that can be included in rate base under Section 16-108.5 of the Act. Deferred Charges as shown in AIC Ex. 1.1, Schedule FR B-1, line 31 and App 5 in the amount of $6,361,000 are incremental costs for a February 2011 storm event. Total incremental costs of $7,951,000 are being amortized over five years, with one-fifth of the cost included in operating expense in the amount of $1,590,000 and the remaining four-fifths, or $6,361,000, of the cost included in rate base, as further detailed in AIC Ex. 1.1, App 7, line 29. Since the storm event occurred in the year prior to AIC's opt-in to formula rates and prior to the first calendar year true-up, AIC does not intend to continue the deferral and amortization of these costs in subsequent formula rate filings. The Commission notes that no party opposes this treatment. The Commission finds the adjustment appropriate and adopts it.

B. Contested Issues

1. Account 909 - Informational and Instructional Advertising Expenses

Within the USOA followed by electric utilities subject to Commission jurisdiction is Account 909 - Informational and Instructional Advertising Expenses. The USOA description of expenses recorded in Account 909 reads as follows:

> This account shall include the cost of labor, materials used and expenses incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

Staff, AG/AARP, and CUB recommend various disallowances of electric related expenses recorded in Account 909. Other than those already agreed to and discussed above, AIC contends that none of the adjustments are warranted.

a. Staff Position

i. "Focused Energy. For Life." Costs

Staff recommends a disallowance of 100%, or $582,137, of the costs for AIC’s FEFL campaign on the grounds that the costs are for advertisements that promote the AIC corporate brand image. AIC introduced the FEFL campaign in 2011. Staff indicates that the FEFL campaign originated from AIC’s “Identity & Education Initiative,” which was designed to “[c]reate stronger relationships with customers, communities, co-workers and other stakeholders” and to “[e]ducate and inform stakeholders on issues of importance.” (Staff Ex. 8.0R-C at 14)

After reviewing the materials AIC provided to support the FEFL campaign (see AG/AARP Ex. 3.4), such as a picture of the Ameren sign at Busch Stadium in St. Louis, Staff asserts that the materials contain no safety, energy conservation, or reliability information. Staff notes further that among the same materials is a discussion of the benefits of corporate branding, which includes the heading “Brand Investment Boosts Our Bottom Line” on page 17 of AG/AARP Ex. 3.4. Staff argues that the FEFL campaign is more about the benefits of corporate branding and image building than it is about providing safety or instructional information. The actual FEFL advertisements and documents, Staff continues, demonstrate that the advertisements are institutional corporate image building, rather than informational and instructional. Examples of such "image building" advertisements in the FEFL campaign include “Powering a Strong Future” and “Employees bring ‘Focused Energy to Life,’" copies of which are available at CUB Ex. 1.3 at page 27 and page 28, respectively. Staff states that these advertisements represent corporate image building and clearly contain no specific information on energy conservation, safety, or reliability.

Staff observes that in Docket No. 12-0001, the Commission found the following with regard to AIC's FEFL campaign:

> Despite AIC’s arguments to the contrary, the Commission is not convinced that AIC’s brand related expenses are recoverable expenses. The types of activities that Staff and the intervenors describe are generally consistent with marketing efforts that fall under subsections (1)(c) and (1)(d) of Section 9-225. How, for example, having customers pay for the development of the phrase "Focused Energy. For Life.", which is used in both Missouri and Illinois, benefits customers as AIC contends is unclear to the Commission. Nor is it clear to the Commission why notice of the name change could not be handled through bill inserts, signage, websites, and call centers despite AIC's argument that such an effort could not be handled through such usual customer contacts. Moreover, the suggestion that such branding expenses are apt to continue in the future conflicts with AIC's assertion that the branding study was necessary in light of the legacy companies merger. For these and the reasons described by Staff and the intervenors, the Commission finds that AIC's brand related expenses should not be recovered from ratepayers. (September 19, 2012 Order at 89)

Staff believes that nothing has changed regarding the FEFL campaign in the few months since the Commission came to this conclusion. Staff also offers that its position is consistent with the treatment this issue received in Docket Nos. 09-0166 and 09-0167 (Cons.). In that rate proceeding, Staff reports that Peoples Gas Light and Coke Company ("Peoples") and North Shore Gas Company's ("North Shore") Safety, Reliability, and Warmth Campaign costs were fully disallowed. Staff avers that a regulated utility has sufficient opportunity through normal communication channels, such as monthly billings, call center contacts, and its website, to advise customers of corporate name changes and other factual information and does not need to enhance the public image of its brand.

Staff recognizes that AG/AARP recommend in rebuttal testimony that the Commission allow 50% of FEFL costs since they find some safety information within the FEFL campaign. Staff understands, however, that AG/AARP witness Brosch had limited time to review AIC's voluminous documents supporting its FEFL campaign costs. (See AG/AARP Ex. 3.0 at 38) Staff finds the evidence that AG/AARP relied upon to recommend 50% recovery to hold little persuasive value and instead suggests that AG/AARP's observations do more to support a complete disallowance. Staff recommends that the Commission adopt its position over that of AG/AARP.

ii. Strategic International Consulting Fees

Staff recommends that the Commission disallow costs totaling $72,540 (electric jurisdictional) AIC paid to Strategic International Group LLC ("SIG") that were not supported as advertising costs. AIC Ex. 14.3 lists the payment to SIG and sets forth the customer benefit and description of the work. AIC describes the customer benefit as "[c]lear and effective communication of customer assistance programs" and the work performed as "[c]onsultation on communication method and message." (AIC Ex. 14.3 at 16-17) Staff observes that during cross-examination, AIC witness Pagel provided more information regarding the nature of the payments to SIG. When asked what specifically AIC received from SIG for $15,000 a month from March through September of 2011, Staff quotes Ms. Pagel as responding, "Basically, his services were consulting service and just the ability to call him when we needed him; consulting services." (Tr. at 147) Staff reports further that AIC's unsigned contract with SIG describes the "Scope of Project" as:

> From March 1, 2011 to February 29, 2012, Strategic International Group will provide consulting and management services specific to issues facing the Client in the areas of government relations and issues management. It is expressly understood that the Services under this contract shall not include any lobbying activities as defined by local, state and federal laws. (Staff Cross Ex. 3 at 23)

Staff avers that nothing in these statements provides evidence of the associated costs being advertising expenses that are allowable under Section 9-225 of the Act.

Staff also points out that AIC waited until its surrebuttal testimony to offer support for its SIG expenses even though Staff proposed its disallowance in its direct testimony. Staff states that AIC's evidence provides generic and conflicting descriptions of the work that was to be performed by SIG. The AIC purchase order authorizing the payment of funds to SIG indicates the work was to "[f]acilitate communications to diverse audiences for various customer related programs: EE and energy assistance in accordance with Scope of Work 1." (See Staff Cross Ex. 3 at 1) Staff observes, however, that nothing in the unsigned contract with SIG or the attached scope of work document references any work on energy efficiency, conservation, or customer programs. Because the purchase order does not agree with the contract, Staff asserts that it is unclear what services SIG performed in exchange for $180,000 over the life of the contract. Staff therefore urges the Commission to accept Staff's adjustment disallowing the electric portion of the 2011 contract costs amounting to $72,540.

iii. Purchase Card Expense

Staff recommends disallowing approximately $27,000 for P-Card expenses recorded in Account 909 on the grounds that they are not recoverable pursuant to Section 9-225 of the Act. This amount represents individual P-Card purchases charged to Account 909 in 2011 that are less than $200. Staff observes that the charges to P-Cards were incurred primarily for meals, purchases at retail stores (Best Buy, Dollar-General, Office Max, Lands End Business, Bees and Blooms, etc.), lodging, and gasoline. Of the total $102,000 total costs attributable to P-Card purchases, Staff points out that AIC provided brief descriptions for only those individual expenses exceeding $200, which amounts to only $75,000 of the total costs. Therefore, Staff suggests disallowing the $27,000 that is not explained.

Staff notes that on cross examination, AIC witness Pagel provided more information regarding P-Card expenditures. When asked how P-Card purchases are authorized, Staff relays that Ms. Pagel testifies that the criteria for the use of the card as well as any limitations are developed on a departmental basis, the details of which she was not aware. In fact, when asked about a spending cap on meals, Ms. Pagel responded, "I don't think there's a defined limit." (Tr. at 166) When asked about certain questionable charges that caught the attention of the Administrative Law Judges, Ms. Pagel's response was as follows:

> Without seeing the rest of the information, I would tend to agree with this because the supervisors approved it. There's a lot more information that you can see. This may be somewhat misleading like Von Maur, they may have bought, I don't know, socks for people doing storm restoration. It's kind of hard to tell, but because they're here and I know they've been approved, I would say that they are costs related to and should be recovered. (Id. at 157)

Staff observes that further cross examination highlighted charges to Macy's, Von Maur, Triple A Trophies, Savvi Formalwear, Marriott Harbor Beach, American Society of Composers, Authors, and Publishers, Alaskan Airlines, Illinois State University Bone Student Center, Lands' End, and a number of florists. (Id. at 156 – 166) From Staff's perspective, AIC appears to believe that simply because costs have been paid (and approved by a supervisor) they are reasonable for recovery as advertising expense.

Staff states further that the testimony of Ms. Pagel at the hearing casts doubt on the recoverability of any portion of the P-Card costs based on the requirements of the Act. (Tr. at 136 – 166) Staff explains that AIC has failed to associate in any way any of the P-Card expenditures booked in Account 909 to advertisements or advertising campaigns. Even though it does not track its P-Card charges to specific advertisements, AIC demands that it should be allowed to recover those amounts from ratepayers since it would require too much effort to track each item. In light of AIC's position, Staff contends that it is impossible to determine whether the expenses are recoverable under Section 9-225 of the Act as an advertising expenditure. In response to AIC's claim that it should not have to provide any nexus between P-Card expenses and advertisements or advertising campaigns, Staff asserts that failing to do so violates Section 9-226 of the Act concerning advertising materials to be made available to the Commission in rate proceedings.

With regard to AIC's complaint that identifying each P-Card purchase of $200 or less with a specific advertisement is not the evidentiary standard for disallowing advertising expenses, Staff argues that AIC fails to appreciate that in seeking to recover these costs as advertising costs, it has a higher standard to meet than is the case for other business expenses. Staff explains that Section 9-225 of the Act states that "the Commission shall not consider, for the purpose of determining any rate, charge of classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer" or is included by the Commission as an allowable category of advertising as set forth in Section 9-225(3). Staff asserts that the Commission cannot determine whether these costs are in the best interests of the consumer because AIC has not provided any indication as to the nature of those costs as required by Section 9-225. Staff also suggests that in order for such costs to be recoverable from ratepayers, the internal controls for P-Card charges should be re-evaluated to conform to rules established for costs designated as advertising expenses.

b. CUB Position

i. "Focused Energy. For Life." Costs

CUB reports that AIC has incurred, and seeks to recover from ratepayers, $582,137 in electric jurisdictional costs related to the FEFL campaign, all of which CUB recommends that the Commission disallow. Section 9-225 of the Act allows a utility to recover, in "any general rate increase," advertising expense that falls into one of several categories so long as the advertising is not political, promotional, goodwill, or institutional in nature. Although AIC points to messages shown in AIC Ex. 25.1 as evidence that the campaign included the types of information for which the Act allows cost recovery, CUB maintains that AIC has not met its burden to prove that the FEFL advertisements are an allowable expense under the categories specifically authorized in Section 9-225. Setting aside the fact that the television and radio commercial advertisement descriptions in AIC Ex. 25.1 were only revealed to the parties in AIC's surrebuttal testimony, CUB states that a close inspection reveals an impermissible purpose behind a number of the advertisements produced. For example, pages 1 and 8 of AIC Ex. 25.1 contain descriptions of very similar television and radio commercials regarding general smart grid investment information. Neither advertisement, CUB observes, includes information about energy conservation, how AIC's customers can ensure service reliability and safety, or information about how AIC's ratepayers should act around downed power lines.

CUB understands from AIC witness Lord that work on the FEFL campaign "developed a mass media commercial that then would direct customers to more information at actonenergy.com," for example. (Tr. at 188) Ms. Lord testifies that the advertising in question should be thought of as a series of educational messages distributed via mass media. She adds that the FEFL campaign is intended to provide "a consistent ending to all of the messages to tie them together as message from the utility." (AIC Ex. 17.0 at 6) She claims that the advertisements at issue are allowable under statutory provisions regarding conservation; service reliability and safety; information about utility functions, terms, and conditions of service; and other categories which are not political, promotional, institutional, or goodwill.

CUB counters that such a design, to tie messages to the utility, is precisely the kind of messaging that brings the utility's name before the general public to improve the image of the utility. CUB insists that the Act bars recovery of the cost of this type of advertising from customers. CUB states further that such consistent messaging underlying FEFL should serve as a signal to the Commission that the FEFL campaign is institutional or goodwill advertising. Moreover, CUB argues that the CoreBrand research project is evidence of the primary design of the FEFL campaign. Although AIC does not seek recovery of its CoreBrand expenses, CUB relates that the purpose of the project with CoreBrand "was to determine if there is a relationship between a company's marketing communication activities and a positive impact [sic] a company's shareholder returns." (AIC Ex. 25.2)

Although introduced in the wake of the merger of the three AIC legacy utilities, CUB also notes that Ms. Lord claims that the FEFL campaign is an effort to ensure that AIC adequately and accurately informs its customers on issues of importance, including energy use and cost; conservation tips and energy efficiency; and safety and reliability messages. AIC provided examples of its messaging in response to a Staff DR concerning AIC's "Informational and Instructional Advertising Expenses." Among the examples provided by AIC is an advertisement that CUB presumes is an actual FEFL full page print advertisement, a copy of which is available on page 27 of CUB Ex. 1.3. The entirety of the text on the ad reads:

> POWERING A STRONG FUTURE
>
> Our region needs energy to grow. That's why AIC is ensuring that Missouri and Illinois enjoy safe, reliable energy. And it's why we're developing renewable sources and technologies for the future, too.

At the same time, our employees are working closely with regional allies to boost our area's economic potential, and helping businesses and families save money through energy efficiency incentives.

Powering a strong future for our region.
That's our focus-now, and for life.

Ameren
FOCUSED ENERGY. For Life.

CUB points out that this advertisement does not contain any information as to how customers should act around downed power lines, how customers can become more energy efficient, or even a reference to any of the three websites that Ms. Lord states contain such information. CUB avers that how such an advertisement achieves any of the educational or informational goals developed by AIC is not explained by AIC and is not apparent from the advertisement itself.

CUB relates that the other four pages provided in response to the Staff DR contain an excerpt from the "Ameren Journal." The "Ameren Journal" is an internal company publication for employees. The excerpt is entitled "Employees bring 'Focused Energy' to life." CUB notes that the publication does not include any customer facing advertisements. (See CUB Ex. 1.3 at 28-31) CUB identifies the following aspects of the document as indicative of the branding purpose of the FEFL campaign:

- The "Ameren Journal" excerpt states, "When we focus our energy on issues that matter, we get results." (See CUB Ex. 1.3 at 28) CUB observes that this advertisement has no specific information on energy conservation, safety or reliability, and is corporate image building in nature.
- The "Ameren Journal" excerpt states, "Creating Value" "People may hear the word 'brand' or 'identity' and think of a company name, logo or tagline. But brand extends beyond those symbols." (See CUB Ex.1.3 at 29) CUB asserts that this statement has no specific information on energy conservation, safety or reliability, and is corporate image building in nature.
- The "Ameren Journal" excerpt states, "Q&A: More than an energy provider … an energy advisor" and includes the inquiries, "How was the format for the educational campaign decided?"…"How are the topics chosen?"…and "Why does Ameren use mass media?". A caption for a picture states, "Customers view Ameren employees as credible sources of information. Employees take center stage in a series of educational television messages to begin airing this fall." The ad also includes the inquiry, "What do customers value?" with balloon containing the responses "price," "service," "reliability," "help reduce use and cost," and "environmental commitment." (See CUB Ex. 1.3 at 30) CUB asserts that this appears to be institutional corporate branding, and has no specific information on energy conservation, safety, or reliability, although it does mention some of these as generalized topics.

- The "Ameren Journal" excerpt states, “What does Focused Energy. For Life. mean to you?” and includes the responses of four AIC employees. CUB describes the responses as "corporate image building type quotes." The bottom of the page contains the following, "Focused Energy. For Life. is our promise. When we consistently keep that promise to our customers, they trust us and understanding we are working in their best interest. And when we earn their trust, we are more likely to gain their support and be successful." (See CUB Ex. 1.3 at 31) CUB observes that no specific information concerning conservation, safety, or reliability is present.

CUB witness Smith sees nothing but institutional corporate image building in the FEFL campaign. Although general references to conservation, safety, and reliability crop up occasionally, he does not consider such sufficient to overcome the apparent primary function of the FEFL campaign as a branding tool. Because the FEFL campaign is essentially a corporate branding campaign, CUB insists that the cost of it should be borne by shareholders.

In response to Ms. Lord's claim that the "Ameren Journal" inserts are allowable advertisements because they contain disclaimers in the material themselves that state that the FEFL campaign is not just an image campaign, but is an effort to educate AIC’s customers that AIC is a resource for energy advice and information (See AIC Ex. 17.0 at 13), CUB contends that AIC’s own disclaimers cannot rectify the deficiencies CUB identifies. Furthermore, CUB points out that the publication containing the advertisement is distributed to employees rather than to customers. CUB states that AIC fails to explain how educating AIC employees on the goals of the FEFL campaign helps consumers save money, stay safe, or learn about customer choice in such a way as to fall into any of the allowable advertising categories listed in Section 9-225 of the Act. CUB reiterates that AIC has failed to carry its burden to prove that these costs are necessary to provide electric delivery services or that they are reasonable in amount.

CUB professes astonishment at AIC's claim in its Initial Brief that because AIC is the only party that has reviewed “all” of the vouchers associated with the FEFL campaign, the Commission should accept AIC’s self-adjustment as sufficient. (AIC Initial Brief at 28) CUB considers this claim invalid for at least three reasons. First, CUB points out that AIC only provided all of the vouchers on August 23, 2012 as voluminous confidential documents, which was only five days before Staff and intervenors’ rebuttal testimony was due to be filed with the Commission. Although Mr. Smith and other witnesses recommended disallowing all of the FEFL campaign costs in their direct testimony, CUB complains that AIC waited until that late date to provide the information. Second, CUB states that Mr. Smith, in fact, reviewed an actual print advertisement from the FEFL campaign included in response to a Staff DR and found no information on how to act around downed power lines, how customers can become more energy efficient, or even a reference to any of the three websites that AIC claims contain such information. Mr. Smith testified as well that the aforementioned Ameren Journal excerpts contained no specific information on energy conservation, safety, or reliability and were found to be corporate image building in nature. Despite the fact that they did not review all of AIC's vouchers for these expenses, CUB maintains that the testimony regarding the purpose behind the FEFL campaign provides sufficient evidence for the Commission to deny AIC recovery for the campaign's costs. Third, CUB argues that the Commission's treatment of the same advertising campaign expenses in Docket No. 12-0001 counsels in favor of complete disallowance here.

c. AG/AARP Position

i. "Focused Energy. For Life." Costs

AG/AARP propose an adjustment removing expenses incurred to conduct image advertising under AIC's FEFL campaign. AG/AARP witness Brosch testifies that these expenses are not reasonable or necessary for the provision of utility services and should be excluded in setting rates. He observes that the emphasis of the ad campaign appears to be intended to promote favorable public opinion of AIC at ratepayers' expense.

Mr. Brosch quotes page 18 of Schedule WPC-8 for a description of the FEFL campaign:

> In 2011, Ameren introduced the corporation's promise, Focused Energy. For Life.—it means that we're focused on making sure the energy vital to life will be there, today and for generations to come. This was a significant efforts [sic] to determine the new promise and to implement the promise reflecting in all company related collateral.

He goes on to relay that page 18 of Schedule WPC-8 also indicates that the FEFL campaign originated from Ameren's Identity & Education Initiative, which is designed to "Create stronger relationships with customers, communities, co-workers and other stakeholders" and to "Educate and inform stakeholders on issues of importance." AG/AARP assert that customers need not pay for advertising that reminds them that the utility provides electric delivery services around the clock or that electricity is essential to living. If AIC elects to incur costs in an effort to enhance its public reputation and to remind customers that it is doing its job, AG/AARP contend that these discretionary expenditures should not be included in the revenue requirement. They argue that AIC has made no showing that these expenses are prudent, necessary, or cost effective in meeting its public utility service obligation.

AG/AARP are not convinced of the appropriateness of the FEFL campaign expenses by AIC witness Lord's testimony that:

> [a]lthough each of the messages concludes with the tagline, Focused Energy. For Life., in conjunction with the logo, the advertising in question should not be thought of simply as Focused Energy. For Life. advertising. Rather, it is a series of educational messages distributed via mass media, which is the most cost effective means of reaching AIC's 1.2 million

> electric customers over its 43,000 square-mile territory. (AIC Ex. 17.0 at 3-4)

They note that she then references Section 9-225(3) of the Act and 83 Ill. Adm. Code 295, "Advertising Expenses of Electric and Gas Utilities" ("Part 295"), to reach her opinion that because some of the challenged advertising references conservation or safety, they are costs that are recoverable. Ms. Lord also indicates that some of the FEFL campaign included messaging to revise existing legacy company advertisements to inform customers that the AmerenCIPS, AmerenCILCO, or AmerenIP entities no longer exist while other ads introduced messages designed to explain that smart grid technologies are used to enhance system reliability.

AG/AARP respond that a regulated utility has sufficient opportunity through normal communication channels to advise customers of corporate name changes and other factual information. As pointed out by Mr. Brosch, monthly billings, signage on buildings and vehicles, its web site, numerous call center contacts, and other customer contacts provide a utility with an opportunity for regular communication with its customers. AG/AARP aver that there simply is no need for significant additional expenditures to enhance the public image of its brand. As a monopoly energy delivery service provider, AG/AARP point out that it is not as though consumers can switch delivery service providers.

AG/AARP report that AIC included substantial amounts of 2011 expenses for printed customer communications, website support, community outreach programs, media placement of advertising, and community outreach programs, in addition to the FEFL campaign costs that Mr. Brosch recommends disallowing, as presented at page 6 of AG/AARP Ex. 3.1. AIC Schedule WPC-8 at page 1 indicates that the $604,302 of FEFL campaign costs represent only part of the $2.5 million of total informational and instructional advertising expense AIC incurred in 2011.

AG/AARP state further that AIC's response to AG DRs 6.24, 6.25, 6.26, and 6.27 included additional details and supporting documentation for the activities and cost elements associated with the FEFL advertising efforts, as listed at pages 18-20 of AIC Schedule WPC-8, that are the subject of the AG/AARP adjustment. Mr. Brosch included in AG/AARP Ex. 3.4 copies of AIC responses to AG DRs 6.24, 6.26, and 6.27 with selected voluminous attachments to illustrate the purposes of the FEFL campaign. For example, AG/AARP state that page 5 of AG/AARP Ex. 3.4 explains the reason why video advertising is used as follows:

> 1.1 Video for education.
> We focus our messaging efforts on education for a variety of reasons. Education can:
> - Help our customers manage their energy use and costs more efficiently.
> - Provide our co-workers with a clear understanding of our business and our strategy and how they contribute to our success.

- Generate a more positive perception in the minds of shareholders and encourage them to keep investing in Ameren.
- Provide regulators and legislators with a more complete understanding of our decisions to assist them as they review pending legislation and rate cases.

AG/AARP observe further that page 17 of AG/AARP Ex. 3.4 contains the heading "Brand Investment Boosts Our Bottom Line" with the following bullet point explanations:

- Corporate Communications plays an essential role in:
  - Improving customer feelings/perceptions
  - Enhancing employee engagement
  - Building community relationships
  - Creating a more favorable regulatory environment
- Corporate Communications activity also creates $ value for shareholders.
- Academic, industry and trade research shows that:
  - Strong brands increase appeal to investors.
  - Strong brands impact company stock performance/TSR.
  - Brand value can be quantified and tracked, like other financial metrics.

Similarly, they point out that pages 27-35 of AG/AARP Ex. 3.4 consist of a report on "Brand Influence" that reveals that much of the rationale behind investing in AIC's FEFL program is to increase the value of the Ameren brand. Based upon his review of these documents that were produced after his direct testimony was prepared, Mr. Brosch revised his proposed adjustment to FEFL costs using a 50% disallowance factor, so as to recognize that these efforts and costs include some messaging that is allowable advertising under the Commission's rules, while also serving the dual purpose of enhancing AIC's image and reputation.

d. AIC Position

i. "Focused Energy. For Life." Costs

The aggregate electric costs for AIC's FEFL campaign amount to $604,302, or almost 25% of the $2.5 million in advertising expenses AIC included in its proposed revenue requirement for Account 909. From that $604,302 amount, AIC has voluntarily removed $22,165 for certain expenses associated with the FEFL campaign, and has reflected that disallowance in the schedules attached to its Initial Brief as Appendix A. Included in that disallowance are the expenses incurred in connection with "brand" research conducted by an outside vendor, CoreBrand. Thus, the remaining FEFL advertising expenses at issue that AIC seeks to recover amount to $582,137.

AIC disputes the arguments of Staff, CUB, and AG/AARP recommending the disallowance of FEFL expenses, but does give credit to AG/AARP witness Brosch for suggesting that AIC be allowed to recover 50% of its FEFL expenses. AIC maintains that the costs associated with the FEFL campaign resulted in a series of educational messages on topics of key importance to customers. According to AIC, the focus of the initiative was identification, development, and delivery of those messages in a clear, consistent, and cost-effective manner. AIC Ex. 25.1 contains examples of the advertising scripts and banners that were developed as a part of the FEFL campaign. AIC states that the messages reflected in AIC Ex. 25.1 pertain to the smart grid, reliability, safety, storm preparation, energy conservation, and energy efficiency. AIC also references the contents of AG/AARP/AIC Cross Ex. 1 as evidence of the FEFL expenses being recoverable. The cross exhibit consists of a document providing talking points on a variety of topics (such as safety, reliability, economic development, and AIC culture) designed to help AIC communicators incorporate FEFL into their message.

With the introduction of any new consumer education initiative and development of associated advertisements, AIC states that there are necessarily costs incurred by the utility for outside vendor services. One of the local vendors used by AIC in 2011 to assist with the rollout of the FEFL campaign was the Simantel Group ("Simantel") with offices in St. Louis and Peoria. AIC asserts that outside vendors like Simantel have the expertise to design and develop the video, audio, print, and digital communications and materials that accompany any advertising initiative. AIC explains further that such outside vendors provide the website professionals who develop, design, and host the websites AIC uses to communicate with its consumers. Such vendors also provide the resources to design booth displays and brochures used at community outreach events. Other services they provide include conducting customer research to identify the topics that customers consider most important and identifying the mediums, including digital mediums, which provide a cost-effective channel for reaching consumers with messaging. According to AIC, outside vendors like Simantel are an essential and integral part of any consumer outreach team. AIC relates that the services provided by Simantel in 2011 helped AIC develop mass media messages and strategies on energy efficiency, energy conservation, safety, storm preparation, reliability, and smart grid. AIC maintains that the costs collectively referred to as FEFL advertising expenses that supported these educational activities are allowable and recoverable expenses under the Act.

Where Mr. Brosch and AIC disagree is the percentage of costs associated with this initiative that should be disallowed and borne by shareholders. In support of his “dual purpose” theory and 50% disallowance, AIC complains that Mr. Brosch pulls out snippets from internal power points and Simantel memorandums, which claimed a relationship between the utility’s “brand” and shareholder value. AIC claims, however, that the support for those statements—and the belief in that correlation—was preliminary research from an outside consultant (CoreBrand) that was later rejected as not reliable. AIC notes that its proposed advertising strategies for 2012 developed in late 2011 lack any discussion of the relationship between “brand” and shareholder value. AIC concurs with Mr. Brosch that shareholders, not ratepayers, should cover the costs associated with CoreBrand. AIC points out that the costs incurred in 2011 related to that research have been identified and removed from the proposed revenue requirement. AIC states that that amount ($5,000), however, represents less than 2% of the costs Mr. Brosch seeks to disallow.

AIC complains that it would be arbitrary and inappropriate for the Commission to disallow all FEFL campaign expenses based solely on Staff's and CUB's unsupported suggestion that every dollar spent in connection with the FEFL campaign was spent with the intention of improving the utility's image. AIC claims that there is not any evidence in the record to support either that assertion or an adjustment of that size. To accept Staff's and CUB's position, AIC contends that the Commission would have to give no weight to the vouchers AIC submitted on these costs, the scripts and ads that were developed, and the testimony of AIC personnel that explained the breadth of this initiative. AIC adds, however, that it would be no less defensible for the Commission to accept Mr. Brosch's proposed disallowance and exclude 50% of the costs associated with FEFL over what AIC perceives to be his concerns with CoreBrand research. AIC believes that the only reasonable outcome is to allow it to recover the FEFL expenses that it has not already voluntarily removed from the revenue requirement. AIC maintains further that the decision to allow or disallow such expenses should be done on a case-by-case, advertisement-by-advertisement basis. AIC states that it is the only party that has reviewed all of the vouchers associated with the FEFL campaign and that the Commission should accept its judgment.

ii. Strategic International Consulting Fees

AIC explains in its surrebuttal testimony that in 2011 SIG provided consulting and management services to AIC for a flat monthly fee of $15,000 to facilitate communications for various customer related programs concerning energy efficiency and energy assistance for low income residents. According to AIC, the services focused on reviewing and commenting on AIC's methods and messages with the goal of making more effective AIC's customer communications. AIC adds that some of the energy assistance programs SIG reviewed are connected with AIC's smart grid investments. AIC also points out that its contract with SIG expressly provided that SIG's consulting services would not encompass lobbying activities as defined by local, state, and federal laws; which AIC considers to be evidence that this contract is for the benefit of consumers. The customer benefits from these consulting services, AIC continues, were improvements in the effectiveness and reach of AIC's energy efficiency and assistance messaging.

AIC disagrees with Staff's position that the record does not support the recovery of payments to SIG. AIC points out that Section 9-225(3) of the Act specifies recovery of advertising for, among other things, energy conservation, energy efficiency, and programs required by law as recoverable expenses. AIC claims that the consulting fees at issue are consistent with the spirit, if not the letter, of the law. AIC considers significant Ms. Pagel's testimony that customers benefited from the messaging that SIG advised on. AIC also notes that there are no allegations that AIC promoted its image with these costs, or otherwise profited from these expenditures. That it negotiated a flat monthly fee for SIG's service does not, AIC argues, demonstrate the expense was unreasonable or unjust. AIC contends that a flat fee just represents the market price for having SIG available at a moment's notice to advise. AIC urges the Commission to reject Staff's proposed disallowance.

iii. Purchase Card Expense

In response to Staff's position that P-Card purchases of $200 or less should be disallowed because AIC did not link each purchase with a specific advertisement, AIC argues that Staff uses the wrong evidentiary standard for disallowing advertising expenses. AIC contends that the evidence Staff demands is neither readily available nor necessary for AIC to carry its burden that these expenses are recoverable business expenses. According to AIC, the fact that it has not manually connected the dots between every $1 charged to P-Cards and a specific advertisement or script produced in 2011 is not proof that supports a disallowance.

AIC points out that in AIC Ex. 14.4 it provided Staff with additional information on the non-invoiced P-Card charges included in Account 909. AIC Ex. 14.4 identified each individual P-Card purchase and provided a line-item description of the purchase/vendor and the amount of the purchase. The amounts ranged from a $0.60 parking charge at Southern Illinois University-Edwardsville on page 3 to an $11,760.69 charge on page 13 from Telephone Marking Programs (TMP) for the cost of white pages, yellow pages, and customer contact directories. In subsequent discovery, Staff asked for the transaction date, description of the materials/services purchased/recorded and cross-reference to the specific advertisement to which each purchase related. AIC, however, does not track or code P-Card charges booked to Account 909 to specific advertisements; rather, AIC's policy is to book P-Card charges to Account 909 whenever the work performed included responsibilities and duties related to an advertising activity. AIC explains that any attempt to provide a nexus between a specific purchase and a specific advertisement would require manual review of the specific charges and manual input of additional information.

Because of the short turnaround time for the discovery response, the numerous small amounts at issue for many of these purchases, and the manual review of the expenses, AIC objected to the scope of Staff's request. AIC was able to provide the transaction date and amount for every individual charge. But instead of manually compiling information on "Description of Material/Purchase" and "Advertisement Reference" for every single P-Card charge, AIC provided Staff with that additional detail on single expenditures greater than $200. Although this represented only 7% of the individual P-Card purchases, it represented 75% of the P-Card dollars. AIC contends that this is a reasonable limitation that provided Staff with additional information for its review on the largest P-Card purchases charged to Account 909 and did not preclude Staff from sending further discovery on individual purchases less than $200 based on the name of the vendor or purchase.

AIC also complains that there is an underlying current to Staff's review of advertising expense, both in Docket No. 12-0001 and this proceeding, namely that the utility's burden is to document and support every dollar charged to Account 909. AIC states that this has led to numerous cost worksheets being produced in both dockets and countless hours spent responding to Staff's discovery requests and disallowances. AIC remains committed to providing Staff with documentation sufficient to support its adverting expenses. But at some point, AIC contends that restraint must be exercised. In AIC's opinion, setting $200 as the floor for providing additional information on P-Card charges was an example of a reasonable restraint, which was further supported by testimony that all of the charges were appropriate business expenses. The Commission should reject Staff's adjustment as unsupported.

AIC also notes that in Docket No. 12-0001, the Commission rejected an adjustment to Account 909 proposed by Staff because Staff did not raise a specific objection to any particular advertising expense. AIC contends that Staff's proposed adjustment concerning P-Card expenses in this docket is analogous to the situation in Docket No. 12-0001. AIC urges the Commission to reject Staff's P-Card adjustment.

e. Commission Conclusion

In resolving the issues concerning Account 909, a review of Section 9-225 is helpful. Section 9-225 provides in relevant part:

> (1) For the purposes of this Section:
>
> * * *
>
> (c) "Promotional advertising" means any advertising for the purpose of encouraging any person to select or use the service or additional service of a utility or the selection or installation of any appliance or equipment designed to use such utility's service; and
>
> (d) "Goodwill or institutional advertising" means any advertising either on a local or national basis designed primarily to bring the utility's name before the general public in such a way as to improve the image of the utility or to promote controversial issues for the utility or the industry.
>
> (2) In any general rate increase requested by any gas, electric, water, or sewer utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section.
>
> (3) The following categories of advertising shall be considered allowable operating expenses for gas, electric, water, or sewer utilities:
>
> (a) Advertising which informs consumers how they can conserve energy or water, reduce peak demand for electric or gas energy, or reduce demand for water;

(b) Advertising required by law or regulations, including advertising required under Part I of Title II of the National Energy Conservation Policy Act;
(c) Advertising regarding service interruptions, safety measures or emergency conditions;
(d) Advertising concerning employment opportunities with such utility;
(e) Advertising which promotes the use of energy efficient appliances, equipment or services;
(f) Explanations of existing or proposed rate schedules or notifications of hearings thereon;
(g) Advertising that identifies the location and operating hours of company business offices;
(h) Advertising which promotes the shifting of demand from peak to off-peak hours or which encourages the off-peak usage of the service; and
(i) "Other" categories of advertisements not includable in paragraphs (a) through (h), but which are not political, promotional, institutional or goodwill advertisements.

i. "Focused Energy. For Life." Costs

Although the Commission considered AIC's FEFL campaign costs in Docket No. 12-0001, the Commission has reviewed all of the FEFL campaign material in this docket in order to re-evaluate the appropriateness of passing such costs along under Section 9-225 of the Act. Unfortunately for AIC, the Commission continues to find that the FEFL advertising costs reflected in the record are consistent with marketing efforts that fall under subsections (1)(c) and (1)(d) of Section 9-225. Staff, CUB, and AG/AARP offer many examples of advertisements from the FEFL campaign that by all appearances have a primary purpose of brand promotion. AG/AARP Ex. 3.4 contains several examples of how FEFL campaign represents a branding campaign. AIC's responses to AG DR 6.24 and AG DR 6.26 discuss extensively branding and the value associated with a positive brand. Only some of the advertisements and associated materials reference safety, reliability, conservation, or some other "recoverable message," and even then such references are brief or offered as suggested talking points for incorporating the FEFL campaign into the message. (See, for example, AG/AARP/AIC Cross Ex. 1, AG DR 6.24, Attachment 10) The Commission recognizes that AIC does not seek to recover the expenses related to CoreBrand and its efforts to measure the connection between brand and shareholder value. But, as CUB suggests, the fact that AIC pursued such research is evidence of AIC's underlying interest in brand identity through the FEFL campaign.

AIC argues that Staff and the intervenors have ignored the many invoices and vouchers that it has submitted in support of the FEFL campaign costs. The fact that AIC received and paid for products and services associated with the FEFL campaign, however, is not what determines whether the expenditures can be included in rates. No one has suggested that AIC has not paid its FEFL bills. AIC Ex. 24.3 consists of 15 pages listing FEFL campaign costs. Columns in the exhibit set forth the "customer benefit" and "description of work" for each invoice. Many of the work descriptions reinforce the notion that the FEFL campaign is a branding effort. For example, the work description provided for several of the invoices from Simantel reads, "Strategy and plan integration of promise into communication materials." (See AIC Ex. 24.3 at 1, 3-8, 10, and 11) The "promise" referenced is AIC's promise to provide FEFL. Such a work description is indicative of FEFL being designed primarily to bring AIC's name before the general public in such a way as to improve the image of the utility. Other customer benefits and work descriptions on AIC Ex. 24.3 reference business retention, business cards for executives, customer surveys preceding new marketing, and updated policy posters for employees. How such expenditures constitute recoverable costs under Section 9-225 is unclear.

Further indication of Ameren's corporate wide marketing efforts is discernible from AIC's September 19, 2012 motion seeking confidential treatment of certain marketing materials found in AG/AARP Ex. 3.4 and AG/AARP/AIC Cross Ex. 1. At paragraph 13 of the motion, AIC asserts that it competes with alternative retail electric suppliers ("ARES") in Illinois' deregulated power supply market, which in AIC's opinion warrants the confidential treatment of its marketing materials. What is interesting about this statement, however, is that AIC is a delivery services company and does not compete against ARES. What competitive interest of AIC would be harmed from disclosure of the marketing materials is not clear. But what this argument does indicate to the Commission is that the marketing effort AIC is concerned about and seeks to pass the costs of along to delivery service customers is actually a corporate wide effort to improve Ameren's name recognition and corporate image.

Accordingly, the Commission finds that the position of Staff and CUB regarding FEFL expenses should be adopted. AIC and Ameren are free to undertake efforts to improve their image and brand, but they may not recover the costs of doing so from regulated AIC delivery service customers.

ii. Strategic International Consulting Fees

The Commission has reviewed the evidence on the issue of SIG's expenses and agrees that there is some ambiguity as to what exactly AIC received in return for its payments to SIG. While AIC makes general assertions that SIG worked on energy efficiency and energy assistance matters and that customers benefitted, Staff maintains that there is no clear indication what type of advertising SIG engaged in. The best evidence in the record of SIG's services comes from Staff Cross Ex. 3, which contains a copy of the unsigned contract between AIC and SIG, a copy of the AIC purchase order, and a document entitled "Scope of Work Number 1" describing the scope of the work to be performed by SIG attached to the contract. As Staff relayed earlier, the scope of work document describes the "Scope of Project" in its entirety as:

> From March 1, 2011 to February 29, 2012, Strategic International Group will provide consulting and management services specific to issues facing

> the Client in the areas of government relations and issues management. It is expressly understood that the Services under this contract shall not include any lobbying activities as defined by local, state and federal laws. (Staff Cross Ex. 3 at 23)

Clearly the "Scope of Project" contains no reference to energy efficiency or energy assistance, but does reference providing services in the areas of "government relations and issues management." In contrast, AIC's purchase order concerning the contract clearly states, "[f]acilitate communications to diverse audiences for various customer related programs: EE and energy assistance in accordance with Scope of Work 1." (See Staff Cross Ex. 3 at 1)

How to reconcile these descriptions is problematic until one considers Section 2 of the contract, which provides:

> Supplier [SIG] shall render the Services and deliver the Deliverables set forth in a Scope of Work to Ameren, and Ameren shall perform its responsibilities set forth in the same Scope of Work. Supplier shall use commercially reasonable efforts to complete work in accordance with the agreed milestones and dates set forth in the Scope of Work. Ameren will issue a purchase order with a Project number assigned. Supplier shall provide the point of contact information, name, address, and e-mail address of the individual who should receive the purchase order to ensure receipt. *In the event the purchase order and/or Scope of Work conflict with the provisions contained in this Contract, except to the extent agreed between the parties in writing, the provisions of the Scope of Work shall prevail over this Contract, which shall prevail over the purchase order*. (emphasis added)

By its own terms, the contract grants priority to the work scope document over the purchase order and the contract itself. In the absence of any specific evidence of SIG's advertising work for AIC and in light of the "Scope of Project" language, it is difficult to conclude that SIG in fact assisted AIC's advertising efforts. AIC's arguments are also suspect in light of its witness' testimony at the hearing when asked what specifically AIC received under the contract, to which she responded, "Basically, his services were consulting service and just the ability to call him when we needed him; consulting services." (Tr. at 147) This testimony indicates a type of retainer arrangement with SIG, which, as already established, does not appear to have involved assistance with AIC's advertising efforts.

From the evidence at hand, the Commission cannot conclude that AIC's payments to SIG represent reasonable advertising expenses that should be recovered from customers. The SIG expenses do not seem appropriate for inclusion in Account 909, nor are they appropriate for recovery from delivery service customers under Section 9-225. Accordingly, Staff's adjustment on this issue is adopted.

iii. Purchase Card Expense

To determine the appropriateness of including P-Card expenses in delivery service rates, it is helpful to first understand how the P-Card system functions. AIC witness Pagel testifies that the P-Card is a credit card obtained by an employee for business expenses. Business expenses paid with a P-Card include food, beverages, taxes, and gratuities; hotels; rental car use for local travel; airline tickets for long distance travel; office items; material and clothing for various community outreach activities; items needed for storm outage and restoration messaging; or just general recurring administrative expenses for a department. She states that several individuals within AIC have their own P-Card, including herself. Supervisors of the various departments determine who receives a P-Card. Approximately every 30 days, each employee with a P-Card must submit a P-Card expense report to their supervisor. The expense report includes a list of charges on the P-Card for that period as well as the receipt for each purchase and an explanation for why the purchase was made. Each expense must be recorded in the proper account, such as meals or travel. If, for example, a meal expense is incorrectly recorded as a travel expense, the employee is given an opportunity to correct the error. Mr. Pagel relates that the department supervisor reviews each expense report and approves or disapproves each charge on the P-Card. If a supervisor is not available, the manager over that supervisor reviews the P-Card expense reports. She is not aware of many P-Card charges being rejected. (See generally AIC Ex. 24.0 at 10-12 and Tr. at 147-166)

In terms of limits on P-Card use, as a supervisor in AIC's Communications Department, Ms. Pagel is most familiar with the limits within the Communications Department, but she is "sure there's a lot of rules around the purchasing card." (Tr. at 148) She explains that each department sets limits on how much money can be spent each month and how much can be spent on each purchase, but she adds "I'm not really specifically sure, but there's different levels for the card use." (Tr. at 149) Within her department, she is not aware of any limits on meal expenses but adds, "I think everybody is trusted to use their common sense plus they usually have a time limitation so it's usually McDonald's." (Tr. at 166) When discussing limits with regard to car rentals, Ms. Pagel states that there is a specific kind of car she is supposed to get. AIC witness Lord adds that there is an emphasis on the core values of integrity and accountability, to be responsible and prudent in the use of P-Cards. (Tr. at 197)

AIC Ex. 14.4 attached to Ms. Pagel's rebuttal testimony (AIC Ex. 14.0) and Attachment A to Staff witness Chang's rebuttal testimony (Staff Ex. 8.0R-C) list AIC's P-Card expenses for 2011. Staff's Attachment A is Ms. Pagel's response to Staff DR KC 15.01 and provides more information than what is contained in AIC Ex. 14.4. (The listed P-Card expenses are the same in both documents.) Specifically, Attachment A reflects the transaction date and a general description of the charge for items over $200. Because Staff's Attachment A to Staff Ex. 8.0R-C provides slightly more information than AIC Ex. 14.4, the former will be referenced in this conclusion.

During 2011, AIC employees collectively charged approximately $102,225 on their P-Cards. A review of Attachment A reveals P-Card charges ranging from less than a dollar to more than $11,000. The spectrum of restaurants visited ranges from McDonald's to Hooters to Biaggi's. The scope of retail establishments at which P-Cards were used covers Wal-Mart and Dollar-General to Von Maur and Eddie Bauer. Clearly, P-Cards are used for a variety of purchases. Determining to what extent the 2011 P-Card purchases represent legitimate and reasonable business expenses under Account 909 is the task at hand. The Commission has no doubt that many of the expenses are appropriately recorded in Account 909 and are recoverable expenses under Section 9-225 of the Act, including some of the charges for less than $200 that Staff seeks to exclude. But exactly which expenses are clearly appropriate is difficult to discern. Staff's generic $200 threshold lacks the specificity which would facilitate making that determination. While the Commission understands the lack of resources that Staff and other parties experience when reviewing the masses of information in a general rate case, let alone those with shortened schedules, as a general matter the Commission is reluctant to disallow costs in the absence of specific concerns with particular expenses.

But in light of some of the descriptions included in Attachment A to Staff Ex. 8.0R-C and given the nature of some of the retailers at which the P-Card was used, the Commission has identified some specific P-Card purchases which it finds questionable. The listed P-Card charges are questionable because the expenses at some retailers are arguably excessive and/or not reasonably related to the provisioning of delivery services. In the absence of better support for these charges, the Commission finds that recovery from delivery service customers is unreasonable. P-Card charges that the Commission will disallow are:

Excluded P-Card Expenses			
Line	Expense Item	Cost	Staff Ex. 8.0R-C Att. A page #
1	AP Bookstore.com	$100.86	5
2	Barnes & Knoble	23.28	5
3	Green Plantscapes Inc	51.71	6
4	Savvi Formalwear	107.91	6
5	Factory Card Outlet	23.27	7
6	Macy's	51.71	8
7	Von Maur	31.03	8
8	AAA Trophies	159.41	9
9	Party City	40.88	11
10	Hobby Lobby	9.94	12
11	Party Worx	9.90	12
12	Lands End Bus Outfitters	45.16	14
13	Bees and Blooms	39.63	14
14	Il Sec of State Lobbyist	186.60	17
15	Lands End Bus Outfitters	41.29	18

16	Lands End Business	25.79	18
17	Peoria Gridiron Dinner	252.00	18
18	Savvi Formalwear	35.95	19
19	Weaverridge Golf Club	37.76	19
20	Finance Charge Cash Adv	27.20	23
21	Autopay Dish Ntwk	260.34	24
22	Becks Engraving and Rubb	73.42	24
23	DIA Development	201.6	25
24	E Bauer	1,955.83	25
25	E Bauer	1,999.19	25
26	Five Star Water Co Inc	93.46	25
27	FTD Becks Florist Inc	98.83	25
28	FTD Carr, Tom Florist	28.78	25
29	FTD Fifth Street Flower	22.44	26
30	Lands End Bus Outfitters	806.76	26
31	Lands End Business	2,124.76	26
32	Proflowers.com	37.16	27
33	The Cubby Hole	1,137.61	28
34	Lands End Business	124.63	30
35	**TOTAL**	**$10,266.09**	

How P-Card purchases at two book retailers at lines 1 and 2 above are related to advertising expenses is not clear to the Commission. The same can be said for the P-Card charges at lines 5, 8, 9, 10, 11, 19, 22, and 26. Other questionable charges are those at Savvi Formalwear at lines 4 and 18 and at upscale retailers Macy's and Von Maur at lines 6 and 7. The Commission does not expect Ms. Pagel to know what every P-Card charge on Attachment A is for, but her suggestion that the charge at Von Maur may have been for socks for those engaging in storm restoration work (Tr. at 157) is difficult to accept. Similarly, the Commission notes that significant sums have been spent at upscale retailers Eddie Bauer and Lands End, apparently for jackets and other clothing for employees (see lines 12, 15, 16, 24, 25, 30, 31, and 34). Over $1,000 was then spent on embroidery at The Cubby Hole (line 33) on some of the clothing. The Commission fails to see why customers must pay for AIC's employees to have high-end, embroidered clothing when the employees encounter those customers. Lines 3, 13, 27, 28, 29, and 32 represent expenses at various florists. While Ms. Pagel testifies that AIC sometimes purchases flowers to make its information booths look more welcoming (Tr. at 164), the Commission does not find such booth decorations an appropriate expense for AIC to expect ratepayers to cover. How purchasing a table at the Peoria Gridiron Dinner (line 17) represents a legitimate advertising expense when employees receive dinner and an evening of entertainment is also unclear. Nor does the Commission agree that purchasing University of Illinois athletic event tickets, under an entry for DIA Development at line 23, constitutes a legitimate advertising expense recoverable from ratepayers. Expecting customers to pay for service from Dish

Network so that employees can track news and storm information (Tr. at 160) is similarly questionable given the prevalence of weather and news services on the internet. Why the P-Card expenses listed at lines 14 and 20 are excluded should be obvious.

Other charges listed on Attachment A have caught the Commission's attention, but because they are conceivably related to advertising activities appropriate for inclusion in Account 909, the Commission will allow their recovery from customers. Among such P-Card charges are two at Best Buy for flip cameras (Attachment A at 5 and 7) and one at Mathis Kelley Construction Supply for two generators (Attachment A at 15). The Commission hopes that AIC keeps such equipment in its inventory following the end of the event that precipitated their need.

Admittedly, even when combined, the disallowed P-Card charges would not make a noticeable difference in customers' bills. But the Commission's primary concern is not how much a P-Card holder spends at Savvi Formalwear, a florist, or any other retailer listed in Attachment A. The primary concern is the apparent lack of controls over P-Card use. The Commission recognizes that Ms. Pagel testified to the existence of limitations on P-Card use, but at the same time she did not seem too sure of the specifics for any of the departments, even her own. This suggests to the Commission that AIC needs to do a better job of educating its employees on P-Card use and setting reasonable limits on usage. One supervisor's or employee's notion of what may constitute reasonable usage may not be the same as another's. Moreover, it does not appear from the record that employees have any incentive to save money when it is the practice to just pass P-card charges along to customers.

To the extent that AIC feels that its current P-Card policies are consistent with general corporate standards, the Commission reminds AIC that such a comparison is not appropriate when the corporate entity in question simply passes purchasing card expenses on to its captive customers. The customers of a typical corporation can choose to spend their money elsewhere if they can find better prices. AIC's customers have no choice but to accept the P-Card purchases in their delivery service rates.

To ensure that AIC implements reasonable usage restrictions on P-Cards, the Commission will require AIC to submit for approval its internal controls on P-Card usage within 45 days of the entry of this Order. Such a filing shall take the form of a petition with the usage limitations and supporting testimony attached. AIC should consider establishing uniform standards for all employees. Such standards should include limitations on meal expenses and identify other ways in which employees will be encouraged to spend wisely. In addition, AIC must provide information on its process for reviewing P-Card expense reports to ensure that they are reviewed in a consistent manner. When expense reports are submitted by employees, it is not unreasonable to expect the employee to report what particular activity he or she was engaged in when an expense was incurred and why that expense was necessary. Such a process is similar to that which State employees follow. Staff's suggestion that AIC be able to provide such information for review by Staff in rate cases is reasonable as well.

2. Account 930.1 - General Advertising Expenses

For more general advertising expenses, the USOA contains Account 930.1 - General Advertising Expenses. The USOA description of expenses recorded in Account 930.1 reads as follows:

> This account shall include the cost of labor, materials used, and expenses incurred in advertising and related activities, the cost of which by their content and purpose are not provided for elsewhere.

Among general advertising expenses not provided for elsewhere are corporate sponsorship expenses. AIC provided several corporate sponsorships amounting to $273,750 (electric jurisdictional) which it recorded in Account 930.1. Among the wide variety of organizations and events to which AIC provided corporate sponsorships that it now seeks to recover from ratepayers are local parades, festivals, plays, concerts, races, and the Illinois State Fair. Pages 3 through 9 of AIC Ex. 24.2 (see also Staff Ex. 8.0R-C, Schedule 8.04) contain a list of events and organizations to which AIC provided funds. AIC voluntary excluded from rates $127,154 in corporate sponsorships. Staff, AG/AARP, and CUB recommend disallowing the remaining balance of corporate sponsorships from the electric revenue requirement.

a. Staff Position

Staff recommends that the Commission disallow certain corporate sponsorships that AIC includes for recovery in Account 930.1 because they are goodwill and promotional in nature. Staff acknowledges that AIC voluntarily removed certain corporate sponsorships totaling $127,154 which were for athletic events and tickets, but Staff insists that the remaining sponsorships should not be recovered as well. Staff observes that during cross-examination, AIC witness Pagel testified that company personnel attended a number of events that AIC sponsored (e.g., Easter Seals Wine and Polo on the Prairie, Lewis & Clark Community College Golf Classic, African American Hall of Fame Dinner). (Tr. at 167 – 170) Staff asserts that these types of events where AIC personnel enjoy the benefits of the event are no different from the specific sponsorships that AIC voluntarily removed from rate recovery. A comparison of the line items in Staff Ex. 8.0R-C, Schedule 8.04 with AIC Ex. 24.2 (at 3-9) shows that 19 out of the 29 items listed were attended by AIC workers. Staff agrees with the characterization of the AIC sponsorships offered by CUB witness Smith:

> The common feature underlying such sponsorships is that they put the Ameren corporate name before the public in a philanthropic light. While Ameren claims this is not the intention of its sponsorships, this is the meaning of goodwill and institutional advertising. Charging ratepayers for this cost would contravene Section 9-225. Ameren can continue to act as a good corporate citizen and enjoy the ensuing benefits, but it should not pass the cost of doing so onto Illinois ratepayers. (CUB Ex. 2.0 at 32-33)

Staff has also reconsidered its position in light of the arguments advanced by CUB and AG/AARP. Staff no longer limits its proposed adjustment to the $54,000 in Schedule 8.04 and now recommends that the Commission disallow all corporate sponsorships. Staff's position is now consistent with that of CUB and AG/AARP.

b. AG/AARP Position

AG/AARP witness Brosch proposes an adjustment for AIC corporate sponsorship of community and sporting events that are discretionary expenses not required for the provision of utility services. Such sponsorship amounts to “goodwill advertising” expenses, which are to be specifically excluded from rates under Section 9-225 of the Act. Subsection 2 of Section 9-225 provides:

> (2) In any general rate increase requested by any gas, electric, water, or sewer utility company under the provisions of this Act, the Commission shall not consider, for the purpose of determining any rate, charge or classification of costs, any direct or indirect expenditures for promotional, political, institutional or goodwill advertising, unless the Commission finds the advertising to be in the best interest of the Consumer or authorized as provided pursuant to subsection 3 of this Section.

Although nothing prevents AIC’s shareholders from sponsoring community and sporting events, AG/AARP avers that such corporate activities constitute a form of promotional or goodwill advertising that offer no specific benefit to AIC’s customers. They maintain that the costs of such corporate activities should be excluded from customer rates.

In response to AIC's argument that its corporate sponsorships support worthy community events and provide opportunities for employees to volunteer, AG/AARP contend that these arguments miss the mark. Community event sponsorship, AG/AARP explain, is a discretionary activity and expense not required to provide public utility services. AG/AARP state that it should be left to AIC to decide if the favorable public image and other intangible benefits that may be realized through such sponsorships are sufficient to justify a dedication of shareholder rather than ratepayer funding in the future. They recommend that Mr. Brosch’s adjustment to remove the costs of these discretionary activities from customer rates be adopted by the Commission. With regard to AIC's reliance on the Commission's findings in Docket No. 10-0467, AG/AARP assert that unlike the record in that case, the record in this case lacks any clear evidence of ratepayer benefit from the sponsorships.

c. CUB Position

AIC has incurred $273,750 in jurisdictional costs related to corporate sponsorships expenses, the entirety of which CUB witness Smith recommends the Commission disallow. CUB states that Section 9-225 of the Act prohibits ratepayer recovery of promotional, institutional, or goodwill advertising, like those costs AIC asks the Commission to allow for corporate sponsorship expenses in Account 930.1. Mr. Smith argues that corporate sponsorships for sporting and cultural events are for corporate image building and should not be charged to ratepayers. He also contends that AIC's expenses in this regard were unnecessary for the provision of safe and reliable electric distribution services. CUB observes that it is not alone in its position on corporate sponsorships, noting that AG/AARP recommend disallowing the entirety of AIC's corporate sponsorship costs in the same amount Mr. Smith recommends.

AIC's argument that its corporate sponsorships allow it to communicate informational and educational messages to its customers does not persuade CUB. Nor is CUB persuaded by AIC's claim that it is appropriate for AIC to recover community event costs because those events depend largely on corporate sponsors. AIC's voluntary removal of some expenses for athletic events and tickets in the amount of $127,154 also does nothing to convince CUB that recovery of the remaining corporate sponsorships is appropriate. To the contrary, Mr. Smith finds the sponsorships that AIC voluntarily removed to be similar to those for which AIC continues to seek recovery.

Mr. Smith argues that Section 9-225 does not distinguish between "community events" and "athletic event tickets" – it disallows promotional, institutional, or goodwill advertising whether AIC received sporting tickets or admission to an event. CUB states further that common among those expenses requested by AIC was that they each put AIC's corporate name before the public in a philanthropic light. Indeed, Mr. Smith points out that Ms. Pagel's own testimony admits that AIC may receive public recognition in the communities it serves by virtue of these sponsorships. (See AIC Ex. 14.0 at 24)

Despite Ms. Pagel's suggestions to the contrary, CUB avers that the Act does not allow utilities to make ratepayers the guarantors of community events or AIC employee volunteer opportunities. Mr. Smith believes that charging ratepayers for these expenses would contravene the meaning behind Section 9-225 since it does not allow goodwill and institutional advertising to be recovered in rates. Mr. Smith notes that AIC is not prevented, by his recommended disallowance, from using shareholder funds to promote its brand to the public. Based on AIC's self-disallowance, CUB suggests that the Commission further disallow at least $155,000 from AIC's operating expenses.

While AIC's sponsorships may be commendable, and AIC is free to continue sponsoring any events it chooses using shareholder funds, CUB asserts that the common feature underlying AIC's sponsorships is that they put the AIC corporate name before the public in a philanthropic light. As the Commission noted in Docket No. 12-0001, the issue here is not whether AIC is free to engage in corporate sponsorships or an assessment of the value of the sponsorship. Rather, what the Commission must determine is whether customers should be required to reimburse AIC for its decision to sponsor an organization or event. Just as the Commission did in Docket No. 12-0001, CUB concludes that the Commission should disallow the costs of corporate sponsorships in this case as well. (See Docket No. 12-0001, September 19, 2012 Order at 95)

d. AIC Position

In preparing its direct case filing for this proceeding, AIC removed from the revenue requirement $127,154 for corporate sponsorships for athletic events that had provided AIC with a tangible benefit in the form of tickets. This amount represents 46% of the electric jurisdictional portion of all of AIC's corporate sponsorship costs in 2011. AIC believes that the remaining corporate sponsorship costs should be recovered in rates. Staff and the intervenors, however, believe that the remaining corporate sponsorship costs in general are image building, institutional advertising expenses that should be disallowed, regardless of whether AIC receives tickets in return.

AIC acknowledges that the Commission addressed this issue in Docket No. 12-0001 and concluded that recovery of corporate sponsorships was not appropriate. AIC argues the Commission reached the wrong conclusion and must not repeat its mistake in this proceeding. AIC states that the Commission previously found that the fact that a utility may receive "public recognition" for its support of civic events does not mean the associated costs are per se unrecoverable and subject to a blanket disallowance. (See Docket No. 10-0467, May 24, 2011 Order at 109) AIC insists that there must be some evidence on the part of the utility that the advertising is meant to be "promotional advertising" or "goodwill or institutional advertising," as those terms are defined in Section 9-225(1). According to AIC, no such evidence of intent exists in the record in this proceeding. AIC insists that the sponsorships at issue here and in Docket No. 12-0001 are no different from the civic event contributions the Commission allowed in Docket No. 10-0467. AIC maintains that any public recognition of the utility associated with the event is secondary to the benefits received by the community.

AIC also argues that the record in this proceeding shows that it sponsors local community events primarily for the additional channels they provide to communicate informational and educational messages to customers. Some events, it notes, allow outreach with the use of a booth, giving AIC a presence to interact directly with customers. Other events offer placement of an ad in the event booklet. Through these events, AIC states that it has the opportunity to educate consumers on energy assistance, conservation, and efficiency programs and incentives, to offer information on safe practices and storm preparation, and to inform customers on outage restoration, reliability initiatives, and supplier choice. AIC Ex. 24.2 identifies the type of presence AIC had at each event (e.g., a booth, an ad, signage, a recycled gift bag, and/or co-worker attendance) and the theme of any presentation (e.g., energy efficiency, reliability, or safety). AIC Ex. 24.2 also includes copies of materials that were distributed at the events.

The basic premise of Staff and intervenors' adjustments, AIC contends, is that the costs benefit primarily AIC, not the customers. AIC characterizes their position as saying that ratepayers are somehow better off without corporate sponsorships of community events, and without these utility interactions. AIC disputes this position and claims that the real beneficiaries of these events are the citizens in AIC's service territory. According to AIC, they benefit, if not by virtue of the event itself, then by the contact and communication with AIC personnel on issues that are important to them. AIC maintains that there is no purposeful attempt to improve AIC's image through the sponsorship of these events or to market Ameren's unregulated services to unsuspecting customers. AIC insists that any benefit from being held in esteem for its sponsorship of local community events is ancillary. Disallowing a business expense simply because it makes the utility look good is not the test. AIC states that under the Act, such expenses are not per se excludable and public policy and ratemaking principles support their inclusion in rates.

e. Commission Conclusion

Account 930.1 reflects a total electric jurisdictional balance of $273,750 representing corporate sponsorships. After excluding AIC's voluntary disallowance of $118,342 (electric jurisdictional), a balance of $155,408 remains in dispute. Staff and the intervenors recommend disallowing this entire amount, consistent with the Commission's decision in Docket No. 12-0001. Unlike Docket No. 12-0001, however, AIC has provided additional information supporting the amounts in Account 930.1. The additional support AIC offers prevents the broad disallowance sought by Staff and the intervenors.

Just as it did in Docket No. 12-0001, the Commission recognizes that corporate sponsorships are important to the success of many organizations and events. The Commission also does not mean to suggest that AIC is not free to engage in corporate sponsorships as it believes appropriate. But the value of the sponsorships to the recipients and AIC's choice of events to sponsor need not be determined by the Commission. Whether customers should have to reimburse AIC for its decision to sponsor an organization or event is what hangs in the balance.

Upon reviewing AIC Ex. 24.2, it is apparent that some of the corporate sponsorships involved useful information from AIC. Others, however, do not appear very different from the athletic events that AIC sponsored and voluntarily withdrew from operating expenses because it received benefits (tickets) in exchange. Before identifying entries in Account 930.1 that are not appropriate for recovery, however, the Commission cautions AIC to be diligent in its recording of costs because some of the entries in Account 930.1 resemble charitable contributions (i.e., $150 to the Pekin Area Chamber of Commerce for fireworks). Admittedly, charitable contributions and corporate sponsorships share some characteristics. To facilitate the Commission's understanding of AIC's policies in this area, the Commission directs AIC to provide in its next rate proceeding its internal definition of "corporate sponsorship" and "charitable contribution," as well as any other guidelines it uses in distinguishing between the two. To the extent that a charitable contribution is recorded in Account 930.1 in this proceeding, it is not the Commission's intent to disallow it for that reason.

The specific corporate sponsorships depicted in AIC Ex. 24.2 recorded in Account 930.1 that the Commission finds questionable are:

Excluded Corporate Sponsorships associated with AIC Ex. 24.2				
Line	Expense Item	Cost	Description	AIC Ex. 24.2 page #
1	Peoria Area Chamber of Commerce	$240	State of the City Address	1
2	Creve Coeur Club of Peoria	1,350	Washington Day Banquet	1
3	Peoria Officials Association	150	Hospitality Room ISHA Basketball	1
4	African American Hall of Fame	1,560	S Cisel Induction into Hall of Fame	1
5	Pekin Area Chamber of Commerce	250	Annual Meeting	1
6	Community Foundation	1,200	Annual Meeting	2
7	East Peoria Chamber of Commerce	300	Mayor's Prayer Lunch	2
8	Lewis & Clark Community College	600	Golf, Godfrey	2
9	Easter Seals Society	900	Wine and Polo on the Prairie	2
10	Greater Decatur Chamber of Commerce	1,200	Thanksgiving Lunch	2
11	Pekin Township Officials	84	WinPak's Benefit Golf	2
12	Peoria Area Chamber of Commerce	192	Heartland Partnership Annual Meeting	2
13	Heart of Illinois United Way	144	ADM, UW and Easter Seals Golf	2
14	Heart of Illinois United Way	106	Kickoff Breakfast	2
15	African American Hall of Fame	3,000	Richard Pryor Memorial Event, Peoria	2
16	Washington Area Community Chamber of Commerce	270	Annual Golf	2
17	Pekin Chamber of Commerce	120	Valuing Diversity Breakfast	3
18	Easter Seals Society UCP	300	Lyle Finch Memorial Claybird Classic	3
19	City of Peoria	1,800	MLK Luncheon	3
20	Peoria Chamber of Commerce	270	Community Thanksgiving Luncheon	3
21	Creve Coeur Club of Peoria	1,350	Washington Day Banquet	3
22	Try County Urban League	150	Golf	3
23	Advertisers Printing	7,027	Booklet - The Story of UE	4
24	Simantel	3,992	Display and materials for Peoria Chiefs	4
25	Advertisers Printing	4,099	Ameren Anniversary Books	4

26	Peoria Heights Chamber of Commerce	180	Membership	4
27	**TOTAL**	**$30,834**		

For several of the sponsorships, AIC received benefits in the form of meals, beverages, and participation in the event (i.e., golf). How these benefits are any different from the athletic event tickets that AIC received with its sponsorships and voluntarily withdrew from its requested operating expenses is unclear to the Commission. Other events that AIC employees simply attended, such as various annual meetings, do not reflect any benefit to either customers generally or the other event attendees. The expenses listed on lines 23 and 25 do not represent events, but rather a booklet and book describing the history of AIC. How spending nearly $11,000 on books describing itself benefits customers and does not constitute goodwill or institutional advertising is not clear. The expense listed on line 24 appears related to AIC's marketing partnership with the Peoria Chiefs for which AIC voluntarily withdrew other expenses. Perhaps the most obvious example of an expense not appropriate for recovery from ratepayers appears on line 4. According to Staff Schedule 8.04 at page 2, AIC spent $2,600 for five tables of ten at a ceremony at which Scott Cisel, AIC's former chairman, president and chief executive officer, was inducted into a local hall of fame. The Commission cannot discern how such an event represents anything other than goodwill or institutional advertising.

In addition to these adjustments associated with AIC Ex. 24.2, the Commission notes that AIC included other expenses recorded in Account 930.1 in an earlier list of such expenses in AIC Ex. 14.2. Between the submission of AIC Ex. 14.2 with AIC's rebuttal testimony and the submission of AIC Ex. 24.2 with its surrebuttal testimony, six entries and an apparent general "catch all" entry disappeared from the list of Account 930.1 expenses. The dollars associated with the entries, however, remained in the total for Account 930.1. The subject entries from AIC Ex. 14.2 are:

Excluded Corporate Sponsorships associated with AIC Ex. 14.2				
Line	Expense Item	Cost	Description	AIC Ex. 14.2 page #
1	Sanders (Cred Coll Sp A)	$57		22
2	Paige (Corp Comm 100)	291		22
3	Palm LMC	210	Labor Day Salute Breakfast	22
4	Frazer (IL Cmty RIPA)	60		22
5	Darflinger (IL Ops Admin)	538		22
6	Paige (Corp Comm 100)	468		23
7	Various	68,601	Various	23
8	**TOTAL**	**$70,225**		

What the expenses at lines 1, 2, 4, 5, and 6 are for is unclear and are therefore disallowed. AIC appears to have received a benefit in return for its sponsorship on line 3. The record also lacks any indication that AIC provided any informational materials at the event listed on line 2. The expense on line 6 concerns the Commission because it is a relatively significant sum (for Account 930.1) representing an apparent "catch all" entry for various expenses. The lack of any discernible support even in the face of CUB and AG/AARP's proposed adjustment dooms this entry to being excluded from recoverable costs.

The amounts associated with AIC Ex. 14.2 and 24.2 total $101,059. The delivery services jurisdictional amount is $94,056. Accordingly, the Commission will disallow $94,056 from AIC's operating expenses.

3. Formula Rate Case Expense - Docket No. 12-0001

The dispute over rate case expense from Docket No. 12-0001 concerns both the disallowance of certain expenses as well as the amortization period of the rate case expense.

a. Staff Position

Staff proposes that AIC be allowed to recover $178,000 (roughly 1/3 of the total amount of $533,317 that Staff finds supported) of its rate case expense from Docket No. 12-0001. The remaining 2/3 would be recovered in rates set in 2013 and 2014. Staff does not recommend recovery of outside legal fees which were redacted. Staff notes that certain descriptions which were not redacted indicate charges for “performance metrics plan,” which is the subject of Docket No. 12-0089. (AIC Late-filed Ex. 2 at 25) In addition, Staff states that charges referring to “Review ALJPO. Research regarding BOE.” would not appear to be related to Docket No. 12-0001 since the case itself had not been filed by the November 9, 2011 date of those activities. (Id. at 30)

Staff also notes that meal costs for Concentric were included in rate case expense for Docket No. 12-0001, which were discussed previously as a component of regulatory commission expense. Based on AIC’s agreement that these costs should not be included in rate case expense, Staff suggests that the Commission make note that this type of cost from Concentric will not be recoverable as rate case expense in subsequent formula rate cases.

With regard to the amortization period for rate case expense, Staff asserts that the Commission should accept Staff’s recommendation to amortize over three years the supported rate case expense incurred in 2011 associated with Docket No. 12-0001 beginning in 2011. AIC proposes to record the costs incurred in 2011 as a regulatory asset to be deferred and amortized over a three-year period beginning in 2012. Staff argues that its position is consistent with Section 16-108.5(c)(4)(E) of the Act:

> (E) recovery of the expenses related to the Commission proceeding under this subsection (c) to approve this performance-based formula rate and initial rates or to subsequent proceedings related to the formula, provided that the recovery shall be amortized over a 3-year period; . . .

Staff maintains that nothing in this subsection provides for the treatment proposed by AIC to defer the costs it incurred in 2011 to begin to be amortized in 2012. Since the instant case considers costs reported in the 2011 FERC Form 1, Staff contends that the costs incurred for rate case expense in 2011 should be considered for recovery in this proceeding.

Staff states further that the September 19, 2012 Order in Docket No. 12-0001 adopted an agreement between Staff and AIC regarding rate case expense. Staff points to the following language from the Order in support of its position:

> Pursuant to Section 9-229, the Commission is required to expressly address in its final order the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts to prepare and litigate a general rate case filing. The costs included for recovery in this filing are amortization of costs approved in Docket No. 04-0294, 07-0585 et al (Cons.), and 09-0306 et al (Cons.) that were previously established as regulatory assets by the Commission in that order. The costs associated with this proceeding were not incurred in 2010 and as such, are not considered for recovery in this proceeding. Costs incurred in 2011 and 2012 that are related to this proceeding will be considered as part of the proceedings related to the recovery of costs for those years. Thus, there are no costs expended by the Company to compensate attorneys or technical experts to prepare and litigate a general rate case filing for the Commission to address in this proceeding. (Order at 193)

According to Staff, AIC agreed during Docket No. 12-0001 that costs incurred in 2011 would be considered part of the proceeding related to the recovery of costs for that year. Staff therefore contends that the Commission should accept its proposal regarding the amortization period of 2011 costs.

Staff is not persuaded by AIC's argument that it will not fully recover its costs under Staff's proposal to amortize 2011 costs over the three-year amortization period of 2011 – 2013. Staff relates that this statement infers that individual components of the revenue requirement will be reconciled. Staff reports that a review of the formula rate schedule FR A-4 (AIC Ex. 11.1, page 6 of 34) reveals that the "Actual Revenue Requirement" on line 1 is compared to the "Prior Year Applicable Net Revenue Requirement" on line 2. Thus, Staff concludes that it is the overall revenue requirements that determine over or under recovery and not the individual components.

b. AIC Position

In response to Staff's proposed disallowance of outside legal expenses, AIC states that it incurred approximately $131,000 in such costs in 2011 related to its initial performance-based formula rate filing. In support of that expense, AIC relates that it provided Staff with invoices for its outside counsel which contained what AIC characterizes as limited, narrowly tailored redactions intended to protect from disclosure information governed by the attorney-client privilege. (See AIC Late-filed Ex. 2 at 4, 14, 22-26, 29-33) Because the invoices contained outside counsel's competitively sensitive hourly rates, AIC states that they also were designated confidential and proprietary. AIC claims, however, that the redactions did not preclude Staff or the Commission from ascertaining the nature of the services performed, who performed them, at what hourly rate, and for what duration.

As AIC understands it, Staff seeks the disallowance of outside legal expenses because AIC did not provide "any explanations of why the information must be redacted from the 'Confidential and Proprietary' version provided to Staff…" (Staff Ex. 6.0 at 23) AIC denies that this is true and asserts that Staff need only consult the narrative that accompanied the invoices for an explanation, which provides "Rates and charges that are Confidential and Proprietary have been redacted in order to preserve the interest of competitive procurement for future legal services. A confidential version will be provided. Certain information, including work descriptions, within the documents have been redacted because they are protected from disclosure by the attorney-client privilege or the attorney-work product doctrine." (AIC Ex. 19.0R at 37 (quoting TEE 6.01S)) AIC states that the explanation as to why certain items were redacted could not be more clear. AIC suggests that Staff may have overlooked the distinction between proprietary information—which is competitively sensitive and therefore afforded limited disclosure (see, e.g., 765 Ill. Comp. Stat 1065/2(d))—and privileged information—for which the protection from disclosure remains absolute, lest it be forever waived. (Ill. Sup. Ct. Rule 201(b)(2); <u>Fidelity & Casualty Co. v. Mobay Chem. Corp.</u>, 252 Ill. App. 3d 992, 1000-01 (1992)) AIC contends that such a misunderstanding is no basis to disallow a reasonable and prudently incurred expense.

In any event, AIC complains that wholesale disallowance is unreasonable. AIC asserts that most of the legal descriptions were not redacted at all and could be easily reviewed. According to AIC, Staff does not explain why the costs of these unredacted work descriptions should be disallowed. Moreover, AIC continues, the redactions at issue protect limited portions of only 33 of 107 work descriptions provided. (See AIC Exs. 19.0R at 38; AIC Late-filed Ex. 2 at 4, 14, 22-26, 29-33) Because the costs are listed on a per-work description basis in the invoices, AIC states that the redactions only affect approximately $50,000 of the total $131,000 cost. But Staff would disallow the entire legal expense, without providing a basis for disallowing the other, approximately $81,000. AIC contends that similar privilege redactions did not preclude Staff in Docket No. 11-0767—a docket from which Staff witness Ebrey otherwise seeks guidance regarding rate case expense —from assessing the utility's outside legal costs. (AIC Ex. 19.0 at 38) As in that docket, AIC asserts that there is ample support in the legal invoices here for the reasonableness of AIC's outside legal expense, without disclosing (and forever waiving) privileged information.

With regard to the amortization period, AIC complains that Staff effectively disallows one-third of the expense remaining after its legal cost adjustment by amortizing the expense in a manner contrary to the Act. AIC relates that the Act permits a participating utility to recover both the rate case expense it incurs in connection with its initial performance-based formula rate proceeding filed under Section 16-108.5(c) and any annual update proceedings filed under Section 16-108.5(d). Recovery of the former, AIC points out, is conditioned on amortization “over a 3-year period.”

AIC explains that in 2011, it incurred approximately $665,000 in connection with Docket No. 12-0001. AIC adds that it has (and will) further incur rate case expense in 2012 associated with Docket No. 12-0001 and the instant proceeding. Consistent with Section 16-108.5(c)(4)(E), AIC proposes to recover the total rate case expense for Docket No. 12-0001 (from both 2011 and 2012) over a single three-year period, beginning in 2012.

In contrast, AIC understands Staff to be calling for the rate case expense to be recovered over several three-year periods, depending upon the year in which the components of the expense were incurred. In other words, Staff recommends that AIC’s 2011 initial formula rate case expense components be recovered in its 2011-2013 revenue requirement period, but its 2012 initial formula rates rate case expense component to be recovered in its 2012-2014 revenue requirement period. AIC asserts that the basis for Staff’s recommendation is not the Act, but rather consistency with what has occurred in ComEd’s formula rate proceedings. AIC argues that ComEd and it need not be treated the same because the pertinent facts are distinct. AIC notes that ComEd opted into formula rates in 2011 while AIC did not opt in until 2012. Therefore, unlike ComEd, which has the opportunity now to fully recover its initial formula rate filing costs incurred in 2011 because it opted into formula rates in that year, AIC states that it would forego its ability to recover in rates subject to reconciliation one-third of its 2011 rate case expense should the Commission adopt Staff’s proposed amortization period beginning in the year prior to the reconciliation. AIC relates that this is because any 2011 expense amount, including amortization, in rates going into effect in January 2013 will be replaced by actual 2013 costs, including any 2011 amortization of initial formula rates costs.

c. Commission Conclusion

The Commission has considered AIC's and Staff's arguments concerning the rate case expenses from Docket No. 12-0001. With regard to the expenses for outside legal counsel, the amounts AIC pays are clearly significant. (See generally AIC Late-filed Ex. 2) The Commission hopes to provide clarification of recoverable expenses in Docket No. 11-0711, a Commission rule-making currently underway concerning the issue of rate case expense. At present, however, the Commission does not share Staff's concerns over the redaction of certain information. The Commission assumes that AIC has claimed in good faith that the redacted information represents attorney work-product and/or a privileged communication between AIC and one of its attorneys. The only exceptions pertain to Staff's observation that one attorney recorded time apparently spent on Docket No. 12-0089 and another recorded time reviewing a proposed order when there would not have been a proposed order to review in Docket

No. 12-0001 at that time. The amount for these activities is $1,760. AIC indicates in footnote 7 of its Reply Brief that it is willing to accept the disallowance of this amount. The Commission finds that an adjustment in this amount is appropriate.

With regard to the meal costs for a Concentric employee who is not on travel status, the Commission notes that AIC does not contest that disallowance. (AIC Ex. 19.0, at 3 and 36) While the amount included in the $664,958 total rate case costs incurred in 2011 is only $138, it is anticipated that additional costs have been incurred during 2012. The Commission finds that an adjustment in this amount is appropriate and further orders AIC to exclude meal costs for Concentric employees who are not on travel status from rate case expense in the subsequent proceeding.

With regard to the amortization period for the rate case expense in Docket No. 12-0001, the Commission has reviewed the arguments of Staff and AIC and finds both lacking clarity. Section 16-108.5(c)(4)(E) of the Act permits a participating utility to, subject to a determination of prudence and reasonableness consistent with Commission practice and law, recover expenses related to the approval of the participating utility's initial performance based formula rate, provided that the recovery shall be amortized over a three-year period. On this, the parties apparently agree. Under the circumstances presented in this case, however, particularly the date on which AIC initiated Docket No. 12-0001, the Commission shares AIC's concerns about underrecovery if Staff's position is adopted. While multiple three-year reconciliation periods may occur as the successive expedited rate cases are conducted pursuant to Public Acts 97-0616 and 97-0646, the Commission is not convinced of the appropriateness of Staff's position to begin amortization of costs from 2011 in the 2011 revenue requirement year in this proceeding, given its concerns about the underrecovery of costs from 2011. Accordingly, AIC's position to not begin amortization of initial performance based formula rate case costs from 2011 in the 2011 revenue requirement year is adopted on this issue. The aforementioned $1,760 and $138 adjustments will not apply until the amortization established in the proceeding subsequent hereto.

4. Regulatory Commission Expense - Docket No. 11-0279

a. Staff Position

Staff recommends that the Commission disallow recovery from ratepayers of the rate case costs incurred for the preparation and litigation of Docket No. 11-0279, which AIC voluntarily withdrew in January 2012. AIC spent substantial amounts of money in an attempt to obtain a rate increase and then abandoned the attempt. Contrary to AIC's position, Staff avers that withdrawal of the rate case was not an action mandated by Public Acts 97-0616 and 97-0646—it was a decision made by AIC alone. Staff states that AIC made a unilateral decision to file the rate case in February 2011 and made the unilateral decision to withdraw the case shortly before the Commission could issue its order in the case. Staff insists that AIC's shareholders, not ratepayers, should bear the burden of the $2,503,519 that AIC spent on Docket No. 11-0279 and now seeks to include in rates.

Staff understands AIC to argue that the costs for Docket No. 11-0279 are recoverable in this formula rate proceeding for the following reasons:

1. They represent actual costs reflected on the 2011 FERC Form 1, and so are recoverable under the terms of the Act;
2. Nothing in the Act indicates that the utility must forego its rate case expense in the event the case is terminated as a result of opting to become a "participating utility;"
3. The withdrawal requirement under the Act was mandatory, not voluntary; and
4. Since 50% of the costs incurred were approved for recovery in Docket No. 11-0282 (AIC's companion gas rate case), the remaining 50% balance should be recovered in this proceeding.

Staff disagrees with each of these points.

Staff asserts that the mere reporting of a cost on FERC Form 1 does not make it recoverable under the Act. Furthermore, Staff points out that a review of the costs beginning on page 2 of AIC Late-filed Ex. 1 indicates that some costs were actually incurred as early as July 2010. While the costs were being incurred, AIC deferred them as regulatory assets. At the end of 2011, when AIC decided to withdraw the rate case filed as Docket No. 11-0279, Staff states that the costs were reclassified to Account 928 and, thus, included in 2011 operating expense even though the costs were actually incurred over more than 2011.

In addition, Staff contends that nothing in the Act provides guidance on the treatment of costs associated with an abandoned rate case, it simply directs that once a utility opts to become a "participating utility," any ongoing rate proceeding must be withdrawn. Furthermore, Staff continues, the mandate to withdraw the rate case is a consequence of AIC's voluntary decision to become a participating utility. Nothing in the Act mandated that AIC become a participating utility.

In rebuttal testimony, Staff offered a proposal that, notwithstanding Staff's primary recommendation to disallow 100% of the regulatory asset for costs associated with Docket No. 11-0279, any amount approved for recovery should be limited to $2,293,000. Staff presents its alternative on Attachment A to Staff Ex. 6.0. Staff's proposed adjustments limit recoverable costs for the following providers:

1. SFIO Consulting ("SFIO") – Staff disallows in total due to services that seem duplicative and redundant of AIC management and legal counsel responsibilities. (See Staff Ex. 6.0 at 15 and Tr. at 442)
2. Legal fees for CW Flynn and Carpenter, Lipps & Leland – Staff disallows costs related to the withdrawal of the rate case in Docket No. 11-0279. (See Staff Ex. 6.0 at 15-16)

3. Accenture – Staff disallows in total due to lack of detail included on the invoices provided to support the requested costs. (See Staff Ex. 6.0 at 16 and Tr. at 436 – 437, 441 - 442)
4. The Communication Counsel of America, Inc. ("CCA") – Staff disallows training costs in total as duplicative of that provided by AIC legal counsel and as unnecessary for AIC witnesses with extensive experience and involvement in prior cases as an expert witness before regulatory bodies. (See Staff Ex. 6.0 at 16-17 and Tr. at 53 - 56)
5. Concentric – Staff disallows meal costs for consultant apparently not on travel status. Similar costs were previously considered and disallowed in Docket Nos. 07-0585 et al. (Cons.). (See Staff Ex. 6.0 at 17 - 18) AIC has agreed to this adjustment.
6. Winston & Strawn, LLP – Staff limits costs for witness James Warren to the more reasonable level granted in the Order in Docket No. 11-0767. (See Staff Ex. 6.0 at 18-19 and Docket No. 11-0767, September 19, 2012 Order at 52)

Staff acknowledges that certain of these costs were considered in Docket No. 11-0282, but adds that a portion of the costs were supported by original invoices for the first time in this case. (See Staff Cross Ex. 1 and AIC Late-filed Ex. 1) In addition, Staff claims to have offered a thorough discussion of the shortcomings found in the evidence. (See Staff Ex. 6.0 at 15-19 and Staff Initial Brief at 27-28) Staff also contends that the Commission's position on what is expected regarding recovery of rate case expense has evolved since the filing of Docket No. 11-0282. The Order in Docket No. 10-0467, which required the initiation of the rate case expense rulemaking, specifically discussed the type of support needed for recovery of rate case expenses. (See May 24, 2011 Order at 65-86) Staff states that that type of support has not been provided for the costs Staff proposes should be disallowed.

With regard to Staff's proposed disallowance of costs to CCA for "witness development skills," Staff points out that during cross-examination, AIC witness Nelson admitted that two of the four witnesses he had listed as inexperienced (AIC Ex. 18.0 at 17), have worked for Ameren for over 20 years and have testified a number of times before the Commission. (Tr. at 44 – 50) For the other two witnesses he listed as inexperienced, Mr. Nelson admitted that he did not know if the witnesses had testified before any regulatory bodies prior to their employment at Ameren and had to some extent based his testimony on discussions with counsel as to the experience level of these witnesses. (Id. at 42 - 44 and 51 – 52) Staff observes that Mr. Nelson next explained that he, himself (Id. at 52-53), along with AIC witnesses Stafford, Mill, and Jones, also participated in the training by CCA. Staff asserts that AIC witnesses Nelson, Stafford, Mill, and Jones are all experienced witnesses before this Commission. (Id. at 54 – 56) Staff avers that the argument that additional training is necessary for these experienced witnesses is without merit.

Staff insists that AIC mischaracterized responses by Staff witness Ebrey regarding her preparation for cross-examination in this case, inferring that her preparation for the hearing in this case was comparable to the training provided by CCA. Staff cites Ms. Ebrey's testimony where she relates how she prepares for a hearing to demonstrate how her preparation is different from that provided by CCA. (Tr. at 444-445) Staff also compares Ms. Ebrey's preparation to CCA's own description of its services, found at pages 404 and 405 of AIC Late-filed Ex. 1. Staff contends that AIC's attempt to draw a parallel between AIC witness training and Staff witness preparation falls short.

b. AIC Position

AIC opposes Staff's recommendation that all of its rate case expenses associated with Docket No. 11-0279 be disallowed. AIC explains that the costs it incurred in relation to Docket No. 11-0279 are prudent and reasonable rate case costs incurred in 2011 and recorded on AIC's 2011 FERC Form 1 in Account 928. As with other recoverable costs reflected on the 2011 FERC Form 1, AIC states that the Docket No. 11-0279 costs are recoverable through formula rates.

In support of its position, AIC claims that its withdrawal of Docket No. 11-0279 was mandatory. That case was filed by AIC in early 2011, consolidated with its concurrently filed gas rate case (Docket No. 11-0282), and litigated for over ten months before enactment of Public Acts 97-0616 and 97-0646. Upon AIC's election to become a participating utility, the revisions to the Act mandated dismissal of the pending electric case.

Staff also argues that the reporting of a cost on FERC Form 1 does not, in and of itself, make the cost recoverable under Public Acts 97-0616 and 97-0646. But, AIC observes, the Section of the Act on which Staff relies provides "[n]othing in [the Act] is intended to allow costs that are not otherwise recoverable to be recoverable by virtue of inclusion in FERC Form 1." (Section 16-108.5(c)) AIC asserts that Staff's position simply ignores that rate case expense is an "otherwise recoverable" operating expense. Nor, AIC continues, can Staff dispute that the General Assembly was well aware of rate case expense. But, while it was very detailed about many of the aspects of the formula rate-setting scheme, the legislature did not specify the treatment of rate case expense incurred related to a withdrawal of a pending electric case. Thus, AIC concludes that the general rule permitting recovery of that expense must apply.

Ms. Ebrey claims further that it is appropriate to disallow the expense because the dismissed electric case "did not improve or enhance the electric service to Ameren electric customers." (Staff Ex. 6.0 at 14) But, AIC argues, that is not the standard for determining whether rate case expense is recoverable. AIC maintains that the standard is whether the expense is just and reasonable.

Staff alternatively recommends, should the Commission disagree with complete disallowance of the Docket No. 11-0279 expense, that it should authorize recovery of $2.3 million as just and reasonable. In light of this alternative recommendation, AIC argues that Staff admits that the costs in question are, in substantial part, reasonable and prudent. AIC finds Staff's alternatives inconsistent in that Staff recommends complete disallowance of an otherwise recoverable operating expense it concedes is largely just and reasonable.

Moreover, AIC continues, the cost components of the Docket No. 11-0279 rate case expense have already been reviewed and approved by the Commission. AIC reports that Staff assessed AIC's rate case expense in Docket Nos. 11-0279/0282 (Cons.) and recommended that the Commission find the total expense (with an uncontested adjustment related to merger costs) to be just, reasonable, and recoverable, with 50% allocated each to the gas rate case and the electric rate case. The Commission agreed with Staff's assessment and authorized recovery of 50% of the total rate case expense in Docket No. 11-0282. AIC explains that the gas portion of the Docket Nos. 11-0279/11-0282 (Cons.) rate case expense was for the same services of the same attorneys and consultants as the electric. The Commission sanctioned recovery of the unsegregated gas portion of those providers' services. As such, AIC argues that Staff's alternative recommendation amounts to no more than an impermissible collateral attack on the Commission's Docket No. 11-0282 Order finding these rate case expense amounts just and reasonable.

In addition, AIC contends that Staff's re-review of individual cost components (witness training costs, for example) and recommended adjustments suggest that corrections to the Docket No. 11-0282 Order are warranted. AIC understands Staff to apparently believe that the Commission's assessment of rate case expense in Docket No. 11-0282 is subject to collateral review because "[t]he Commission is currently evaluating rate case expense with greater scrutiny than in the past." (Staff Ex. 6.0 at 20) AIC responds that the scrutiny already had begun by the time the Docket No. 11-0282 Order was issued, and that Order indicates a full review was undertaken. Ms. Ebrey points to several dockets, including Docket No. 10-0467, wherein the Commission ordered a rulemaking related to rate case expense, and Docket No. 11-0711, the rulemaking docket itself in support of her position. But both the Commission's Order in Docket No. 10-0467 and its Initiating Order in the rulemaking preceded its Docket No. 11-0282 Order. Therefore, AIC finds Ms. Ebrey's position to be misplaced. Further, in its Docket No. 11-0282 Order, AIC contends that the Commission made abundantly clear the substantial scrutiny it accorded AIC's rate case expense:

> The Commission notes that, in light of the relatively recent enactment of Section 9-229 and the related issues raised in recent rate cases, the Commission is taking a closer look at rate case expense. On November 2, 2011, the Commission initiated a rulemaking in Docket No. 11-0711 to allow all interested parties to participate in formulation of rules regarding the issue of rate case expense.
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> Given the timing of the rulemaking proceeding that has begun and the case herein, the Commission is without the benefit of those new

> standards. Nevertheless, the Commission is cognizant that a thorough analysis of these costs is required in order to approve such costs under Section 9-229 as well as the recent Court opinion . . . . AIC presented extensive information in support of its requested level of rate case expense, including information regarding amounts expended to compensate attorneys and technical experts. (Order at 45-46)

AIC argues further that Staff's specific adjustments can be rejected on their merits. First, Ms. Ebrey recommends that Accenture's cost be disallowed because she believes that the consultant's invoices are vague and "the identity of the witness is not known." (Staff Ex. 6.0 at 16) Yet, she admitted that a cursory review of the Docket Nos. 11-0279/0282 (Cons.) record shows the witness was James Mazurek. (AIC Ex. 18.0R at 16 (citing AIC-Staff 11.01, 11.02)) AIC states that Ms. Ebrey similarly recommends disallowance of SFIO's fee based on her belief that the consultant's invoices are vague. (Staff Ex. 6.0 at 15) While Ms. Ebrey deems recovery of a consultant's expense largely dependent upon the level of detail in its invoices, AIC states that neither Section 9-229 nor the Commission do. AIC reiterates that the Commission looked favorably upon the information provided in Docket No. 11-0282 and expressed no concern regarding the level of detail in consultant invoices.

Second, Ms. Ebrey recommends disallowance of the costs of outside counsel related to withdrawal of Docket No. 11-0279. The record in that proceeding, however, demonstrates AIC filed a motion to dismiss the electric case prior to the dismissal mandated by the Act. Had that motion been granted, AIC states that further incurrence of rate case expense would have been mitigated. Thus, AIC continues, certain outside counsel fees were incurred, in part, to limit costs.

Third, Ms. Ebrey recommends disallowance of the cost of a witness development program utilized by AIC to prepare witnesses for hearing because she believes it is unclear why experienced expert witnesses require additional training. AIC complains that this shows an ignorance of the record of those proceedings. According to AIC, a number of its witnesses were not experienced expert witnesses, but rather AMS employees with job responsibilities other than testifying in proceedings before regulatory bodies. Moreover, AIC contends that simply because a witness has experience testifying does not mean they cannot benefit from additional preparation.

Finally, Staff recommends partial disallowance of the cost of AIC's tax expert in Docket No. 11-0279 because it now believes his rate is too high. AIC witness Nelson testifies that Mr. Warren is a nationally recognized tax attorney and tax expert specializing and practicing exclusively in the area of tax. Rather than evaluating his experience, skill, knowledge, expertise, credentials, the hourly rate for other senior attorneys in his practice area and locale, the total dollar amount of the adjustments regarding which he testified in Docket No. 11-0279, or the expediency or efficiency with which he addressed those issues, AIC complains that Staff simply recommends supplanting that expert's hourly rate with the confidential rate of another consultant (a certified public accountant) hired by another utility in another docket. AIC does not consider this appropriate.

c. Commission Conclusion

With the enactment of Public Acts 97-0616 and 97-0646, AIC had a choice to make. Under the revisions to the Act, AIC was eligible to choose to become a "participating utility" and enjoy the benefits of the formula rate methodology. Upon choosing to do so, however, it knew that Section 16-108.5(c) would require it to withdraw its pending electric rate case, Docket No. 11-0279, and that the Commission would be statutorily mandated to approve that withdrawal. Accordingly, AIC had to choose between completing its electric rate case and participating in a grid modernization program. Regardless of the advantages and disadvantages of AIC's options, the choice was AIC's to make.

When it initiated Docket No. 12-0001, AIC made its choice to become a participating utility. The Commission dismissed Docket No. 11-0279 with prejudice as required on January 5, 2012. No mention of rate case expense was made in the Order. AIC now seeks to recover the costs of the electric rate case that it voluntary chose to withdraw through its election to become a participating utility under Section 16-108.5 of the Act.

Section 16-108.5(c) of the Act also provides, in relevant part, as follows:

> In the event the participating utility, prior to the effective date of this amendatory Act of the 97th General Assembly, filed electric delivery services tariffs with the Commission pursuant to Section 9-201 of this Act that are related to the recovery of its electric delivery services costs that are still pending on the effective date of this amendatory Act of the 97th General Assembly, the participating utility shall, at the time it files its performance-based formula rate tariff with the Commission, also file a notice of withdrawal with the Commission to withdraw the electric delivery services tariffs previously filed pursuant to Section 9-201 of this Act. Upon receipt of such notice, the Commission shall dismiss with prejudice any docket that had been initiated to investigate the electric delivery services tariffs filed pursuant to Section 9-201 of this Act, <u>and such tariffs and the record related thereto shall not be the subject of any further hearing, investigation, or proceeding of any kind related to rates for electric delivery services.</u> (emphasis added)

In reviewing the arguments of Staff and AIC on this issue, it is clear that AIC is attempting to avoid the negative consequences of its own decision to forego its electric rate case. The Commission recognizes that AIC has recorded its rate case expenses from Docket No. 11-0279 on its 2011 FERC Form 1, but does not agree with the implication of AIC's argument that whatever AIC records on FERC Form 1 is recoverable. As AIC itself observes, Section 16-108.5(c) provides that "[n]othing in this

Section is intended to allow costs that are not otherwise recoverable to be recoverable by virtue of inclusion in FERC Form 1." Generally, so long as they are prudent, just, and reasonable, and otherwise within the parameters of Section 9-229, rate case expenses are recoverable. Also, generally rate cases are completed with an order balancing the interests of a utility and its customers to their mutual benefit. With the dismissal of Docket No. 11-0279, AIC and its customers were left with many rate and tariff issues undecided. AIC's desire to recover its expenses on a voluntarily abandoned effort is not well taken by the Commission. The inclusion of its rate case expenses from Docket No. 11-0279 on its 2011 FERC Form 1 does not ameliorate the Commission's view, especially given the language in Section 16-108.5(c).

The clear language of Section 16-108.5(c), quoted above, states that nothing contained in the electric portion of Docket No. 11-0279 is to be heard in any other proceeding. Thus, the Commission believes the General Assembly was dictating that AIC's costs for its expenses related to litigating Docket No. 11-0279 could not be recovered. To read otherwise would be unjust and unreasonable to AIC's ratepayers, but not to AIC which made the decision to become a participating utility under EIMA. Accordingly, the Commission will disallow $2,503,519 in rate case expenses from Docket No. 11-0279 allocated to electric delivery services.

Even if Section 16-108.5(c) did not serve as a statutory bar to recovery, the Commission believes these expenses are inappropriate for recovery under the Commission's mandate to "specifically assess the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts" pursuant to Section 9-229 of the Act. AIC argues that no party has challenged the prudency of its election to become a participating utility under Section 16-108.5 of the Act (and thus withdraw its rate case), and thus that recovery under Section 9-229 should be allowed. While this may be accurate, it is also true that for rate expenses to be recovered from ratepayers, they must also be just and reasonable. Recently, the Illinois Appellate Court provided guidance regarding how to appropriately apply Section 9-229, and instructed the Commission to look at the following factors:

> [W]e point the Commission to other cases involving an award of attorney fees, in which the party seeking attorney fees must specify (1) the services performed, (2) by whom they were performed, (3) the time expended, and (4) the hourly rate charged. Fitzgerald v. Lake Shore Animal Hospital, Inc., 183 Ill. App. 3d 655, 661 (1989) (citing Kaiser v. MEPC American Properties, Inc., 164 Ill. App. 3d 978, 984 (1987)).
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> "Once presented with these facts, the trial court should consider a variety of additional factors such as the skill and standing of the attorneys, the nature of the case, the novelty and/or difficulty of the issues and work involved, the importance of the matter, the degree of responsibility required, the usual and customary charges for comparable services, the benefit to the client [citation], and whether there is a reasonable

> connection between the fees and the amount involved in the litigation [citations]." Kaiser, 164 Ill. App. 3d at 984.

People Ex Rel Madigan v. ICC, 2011 IL App (1st) 101776, ¶ 51.

By voluntarily electing to become a "participating utility" under Section 16-108.5 prior to the conclusion of its Docket No. 11-0279 rate case, AIC effectively withdrew its case on its own initiative and ensured the docketed proceeding would not reach its intended conclusion. Withdrawal of the matter left nothing at stake, and thus forfeited any possible "connection between the fees and the amount involved in the litigation" as the litigation no longer concerned any amount. The Commission cannot in good conscience consider it just and reasonable to recover from ratepayers fees for a case which failed to update AIC's delivery service rates due to the company's own election. Thus, the Commission finds that even if these fees were not subject to a statutory bar on their recovery under Section 16-108.5(c) of the Act, the Commission would deny their recovery from ratepayers under Section 9-229 of the Act.

5. Deferred State Income Tax Expense

In 2011, the Illinois Income Tax Act ("ITA"), 35 ILCS 5/101 et seq., was amended to provide for an increase in the SIT rate. The change in Illinois' corporate business income tax rate, codified at Section 201 of the ITA, caused AIC's SIT rate to increase from 7.3% to 9.5% in years 2011 through 2014, with a reduction to 7.75% in 2015 followed by a further reduction to 7.3% in 2025. AG/AARP, CUB, and Staff maintain that AIC has failed to account for reductions in the tax rate.

a. AG/AARP Position

AG/AARP witness Brosch proposes an adjustment to AIC's asserted income tax expenses to account for the full impact of the SIT rate changes occurring in 2011. He explains that AIC has recognized only part of the higher Illinois corporate income tax rate that is effective in 2011 in its proposed inception revenue requirement. AIC Ex. 1.1 at Schedule C-4 reflects utilization of the new higher 9.5% Illinois state tax rate at line 2, to calculate the "Incremental Tax Gross Up Factor" that is used on Schedule FR A-1 at line 16. Unfortunately, Mr. Brosch observes that AIC's calculations assume that AIC will experience taxable income and actually pay taxes at these higher rates, even though all of AIC's current SIT obligations in 2011 are actually being deferred into future years.

AG/AARP state that the scheduled reductions in future Illinois SIT rates result in significant income tax savings to AIC. AG/AARP explain that AIC tax deductions taken today will produce income tax deferrals today when tax rates are at the higher 9.5% rate, creating book/tax timing differences and deferred income taxes today that will reverse in future years, at which time income taxes will then become payable at the lower tax rates scheduled to be effective at that time. AG/AARP contend that this phenomenon is completely ignored in AIC's filing, but is the subject of specific large ratemaking adjustments in ComEd's formula rate update filing in Docket No. 12-0321.

Mr. Brosch quotes ComEd's witness on this issue extensively to demonstrate ComEd's recognition of the situation. (See AG/AARP Ex. 1.0 at 31-32)

AG/AARP further note that the income tax expense adjustments that ComEd proposes in Docket No. 12-0321, due to a lower future SIT, are individually significant. Mr. Brosch points out that one such adjustment results in a 2011 income tax expense benefit of $16.9 million. This adjustment is quantified at ComEd Ex. 3.2, WP 9, page 2 of 4 and results from utilization of lower income tax rates to calculate deferred income tax expenses in 2011, in anticipation of reversal of book/tax timing differences in future years when SIT rates are scheduled to be lower.

AG/AARP argue that ComEd's discussion of the revenue requirement effect of the SIT rates and Generally Accepted Accounting Principles ("GAAP") apply equally to AIC. While the specific tax deductions, tax credits, and income levels are obviously unique to each of the two utilities, AG/AARP aver that there is no reason why only ComEd is able to benefit from the expected turnaround of tax deferrals in future, lower-rate tax periods. AG/AARP state that AIC offers no testimony or calculations indicating how the changing Illinois SIT rates will impact its ADIT accounting or recorded deferred income tax expenses.

AG/AARP report that AIC explains the absence of deferred income tax expense adjustments comparable to those included in ComEd's formula rate filing in its response to AG DR 2.04, in which AIC was asked to explain the omission of comparable adjustments in its filing in Docket No. 12-0293. In its response to part (d) of this question, AIC states, "See AG 2.04 Attach 2 which identifies only the schedule m's that were booked during the normal course of the year with a difference between current and deferred income tax expense. The jurisdictional amount is a reduction to income tax expense of $27,995." In response to part (e) of this DR, AIC states, "AIC is not proposing ratemaking treatment of the SIT rate differential impacting ADIT, as quantified in response to part (d), based on past practice of the Commission in calculating income tax expense at statutory rates." AG/AARP Exhibit 1.7 contains a copy of AIC's response to AG DR 2.04.

Mr. Brosch verifies that AIC is deferring large amounts of SIT in 2011 at Schedule C-5a, page 3, line 65, wherein AIC indicates that calendar year SIT expenses that are currently payable are negative $16.3 million, while deferred SIT are positive $28.3 million. This means that AIC's current state taxable income is negative, because tax deductions and tax credits exceed taxable revenues. Yet, he observes, AIC's revenue requirement will recover large amounts of "deferred" income taxes that will serve to reduce rate base until such amounts become payable in future tax years.

AG/AARP understands AIC to concede that the phenomenon of having a tax rate increase generating tax savings should be reflected in the revenue requirement and that this phenomenon is material in 2011, with the tax rate change not being permanent. Unfortunately, they find AIC witness Stafford's method of reflecting the tax rate change phenomenon in the calculation of revenue requirement much different than the adjustments they and CUB propose and much different than the treatment of this same issue by ComEd in Docket No. 12-0321. Mr. Brosch revised AG/AARP Exhibit 3.1 to include the revised downward adjustment to income tax expense that Mr. Stafford presented. AG/AARP recommend that AIC's 2011 income tax expenses for ratemaking purposes be reduced by the net amount of $4.137 million to account for the temporary nature of SIT rate changes.

But even though AIC conceded the need to recognize the expense impact of SIT rate changes, AG/AARP assert that another adjustment is still needed. As Mr. Brosch notes, AIC proposes to include only one-fifth of the expense reduction within income tax expenses. Mr. Stafford testifies, "Ameren Exhibit 11.1, Schedule FR B-1, line 31 and App 5 have been adjusted to reflect amortization of the $4.137 million credit due to the tax rate change. Total costs of $4.137 million are being amortized over 5 years, with 1/5 of the cost included in operating expense in the amount of $827,000 and the remaining 4/5, or $3,310 million of the credit included in Rate Base, as further detailed in AIC Exhibit 11.1, App 7, line 29." (AIC Ex. 11.0R at 39) AG/AARP contend, however, that the problem is that by "amortizing" the 2011 permanent income tax expense savings over five years, AIC will effectively deny ratepayers participation in the other four-fifths of the annual deferred income tax expense savings caused by temporarily higher SIT rates in 2011. The adjustment now set forth in AG/AARP Exhibit 3.1, page 4, replaces the four-fifths share of the needed adjustment to income tax expenses, moving this amount from rate base back into the 2011 operating income computations.

AIC offers two reasons for its deferral and amortization treatment of permanent income tax expense savings. First, according to Mr. Stafford, "Since this tax rate change exceeds $3.7 million, Section 16-108.5(c)(4)(F) of the Act requires charges or credits 'including those related to taxes' to be recognized as a deferral subject to amortization, consistent with the charge for an incremental storm event that was deferred in the Company's direct filing." Then, he states, "Consistent with treatment of the incremental storm event discussed at pages 22-23 of my Direct Testimony, which no party opposed, since the tax rate change giving rise to the deferred income tax expense reduction occurred in the year prior to AIC's opt-in to formula rates and prior to the first calendar year reconciliation and true-up, the Company does not intend to continue the deferral and amortization of this credit in subsequent formula rate proceedings." (AIC Ex. 11.0R at 39)

In response, AG/AARP argue that the effect of AIC's proposed treatment of deferred income tax expense savings arising from the temporary increase to SIT rates is to deny ratepayers participation now, or in future years, for the other four-fifths of permanent income tax expense savings experienced by AIC in 2011. Mr. Brosch testifies that his understanding of Mr. Stafford's reference to storm costs is that AIC intends to not credit ratepayers for any of the last four years' amortization for the permanent income tax savings he would "defer" in 2011. In fact, AG/AARP continue, the 2011 income tax savings arising from temporarily higher SIT rates should not be deferred and amortized. Mr. Brosch asserts that these are permanent and ongoing expense savings and are not abnormal or non-recurring in nature. He contends that these income tax savings are not comparable to large and unusual storm restoration events or one-time severance events that are routinely deferred and normalized for ratemaking purposes. AG/AARP find Mr. Stafford's analogy to storm costs inapplicable to the SIT rate change income tax savings that AIC can expect to realize in each future year under current law.

Moreover, AG/AARP maintain that deferral and amortization of the 2011 income tax savings arising from temporarily higher SIT rates are not required under Section 16-108.5(c)(4)(F) of the Act. This Section provides for:

> (F) amortization over a 5 year period of the full amount of each charge or credit that exceeds $3,700,000 for a participating utility that is a combination utility or $10,000,000 for a participating utility that serves more than 3 million retail customers in the applicable calendar year and that relates to a workforce reduction program's severance costs, changes in accounting rules, changes in law, compliance with any Commission initiated audit, or a single storm or other similar expense, provided that any unamortized balance shall be reflected in rate base. For purposes of this subparagraph (F), changes in law includes any enactment, repeal, or amendment in a law, ordinance, rule, regulation, interpretation, permit, license, consent, or order, including those relating to taxes, accounting, or to environmental matters, or in the interpretation or application thereof by any governmental authority occurring after the effective date of this amendatory Act of the 97th General Assembly;

AG/AARP understand Mr. Stafford to focus on the phrase "including those relating to taxes" and apparently believes that the SIT rate change impact should be deferred because it falls within the "changes in law" element of the listing in this section. They counter, however, that the overall net impact of the changes to income tax expense arising from new SIT rates does not reach the $3.7 million threshold that requires deferral and amortization.

Mr. Stafford observes that the change from 7.3% to 9.5% SIT rates within AIC's calculation of current income taxes on Schedule C-5a produced a net increase in state and federal income tax expense of $1,813,717. Then, in response to Mr. Brosch, Mr. Stafford admits that, "As shown on Ameren Exhibit 11.3, the change in deferred income tax expense of calculating current income tax expense at 9.5% but amortizing 2011 tax benefits at 7.75% or 7.3% results in a reduction to 2011 actual jurisdictional income tax expense of $4.137 million." (AIC Ex. 11.0R at 37) AG/AARP then calculate that the overall net impact of the SIT rate change, using AIC's numbers, is the combined increase of $1,813,717 less the reduction of $4,137,000, which nets to $2,323,283. AG/AARP conclude that this $2.3 million net impact arising from SIT rate changes does not meet the criteria specified in the referenced section of the law.

AG/AARP state further that irrespective of the dollar threshold for changes in law under formula ratemaking, deferral and amortization of AIC's deferred income tax expense savings arising from SIT rate changes is not appropriate. Unusual, extraordinary events or costs that are non-recurring in nature are often considered for deferral and amortization ratemaking, so as to spread out and "normalize" the amounts included in revenue requirements to be paid by customers. For example, the high expenses that are incurred by utilities after extreme storm events in order to quickly restore service are routinely deferred and amortized by regulators to avoid setting rates as if such severe storms occur in every year that new rates are in effect. In contrast, AG/AARP aver that the higher currently payable income taxes and the offsetting deferred income tax expense savings created under revised SIT rates are not unusual, extraordinary, or non-recurring. AG/AARP contend that the pattern of higher current income taxes offset by lower deferred income tax expenses for property-related book/tax timing differences will persist in future years. AG/AARP insists that it would be inappropriate as a matter of ratemaking policy to defer and amortize a pattern of income tax expense impacts under new SIT rates that will be recurring in future years.

Additionally, as mentioned earlier, AIC will not actually pay income tax expenses at the new 9.5% rate on all of its income earned under Illinois formula ratemaking. AG/AARP reiterate that AIC is not currently paying any SIT, and AIC's calculated overall tax expense reveals an expectation of continued negative currently taxable income in the future. Large income tax deductions have resulted from tax accounting changes adopted by AIC that permit current deduction as "repairs" expenses for property-related costs that are capitalized on the books as Plant in Service. AG/AARP explain that these deductions, as well as the continuing large deductions for "bonus" tax depreciation in 2012, have the effect of deferring AIC's income tax liability into distant future periods when Illinois SIT rates are scheduled to revert to lower levels. Even if circumstances change, such that AIC begins paying income taxes at the higher currently effective SIT in future years, AG/AARP state that annual formula ratemaking will allow AIC to recognize and fully collect income tax expenses under then current conditions. These annual proceedings, AG/AARP argue, provide AIC with an opportunity to annually update the relevant calculations to revise total income tax expense for all of the impacts (current and deferred expense provisions) caused by the SIT rate change.

b. CUB Position

In light of the statutory scheduled reductions in the SIT rate and consistent with the proposal by ComEd in Docket No. 12-0321, CUB recommends that AIC's operating expenses be reduced by $4.137 million. CUB witness Smith explains how AIC initially failed to recognize the effect of the change in SIT rates by negating any impact of making an adjustment on its Part 285 Schedule C-5.2. Instead, Mr. Smith calculates this adjustment similar to ComEd's treatment of the issue, since both use the same FERC USOA and similar state regulatory and ratemaking principles. Mr. Smith notes that because of the similar situations between the two utilities with respect to this issue, the deferred 2011 SIT expense should be similarly reflected in the utilities' formula rate filings under Section 16-108.5 of the Act. Mr. Smith's adjustment also accounted for the effect of the change in SIT on federal income taxes, and came to an amount similar to AIC witness Stafford's calculation in his rebuttal testimony ($3.983 million versus $4.137

million). In his own rebuttal testimony, Mr. Smith agreed with Mr. Stafford's calculation of the $4.137 million net deferred SIT savings.

CUB observes, however, that Mr. Stafford testifies that he separated two components of the change resulting from the SIT law because he believed that Section 16-108.5(c)(4)(F) "says that specifically that you have to consider each charge or credit separately." (Tr. at 231) Despite this interpretation, CUB continues, Mr. Stafford admits that neither of the two changes that he "separates" would have occurred absent the General Assembly's singular action to change the SIT rate. Indeed, CUB states further, AIC admits that "[s]ince Ameren is required to maintain its books and records in accordance with [GAAP] and in accordance with any and all other tax guidance and accounting authority applicable to utilities, as does ComEd, AIC does not expect that there would be any material difference in implementation of the SIT rate change." (AG/AARP Ex. 1.7 at 2)

As for Mr. Stafford's proposed deferral and amortization of the SIT tax rate change impact on deferred income taxes only, CUB insists that it is improper and must be rejected. As an initial matter, CUB notes that Section 16-108.5(c)(4)(F) of the Act provides for amortization "of the full amount of each charge or credit that exceeds $3,700,000 … in the applicable calendar year and that relates to a workforce reduction program's severance costs, changes in accounting rules, changes in law, compliance with any Commission initiated audit, or a single storm or other similar expense." Changes in law include "those relating to taxes… occurring after the effective date of this amendatory Act of the 97th General Assembly." CUB states that the overall net impact of the SIT rate change, according to AIC's own calculations, is $2,323,283. AIC argues that netting the two amounts is not contemplated by the statute since it requires amortization "of the full amount of each charge or credit," claiming that the current tax increase and the deferred tax reduction are separate "charges or credits." (AIC Initial Brief at 48) CUB contends that this interpretation of the Act ignores the rest of that provision of the law, which requires that any change in law must occur "**after** the effective date of this amendatory Act of the 97th General Assembly" to trigger the amortization provision. (Section 6-018.5(c)(4)(F)(emphasis added)) CUB reports that the effective date of the amendatory act which created the amortization provision was October 26, 2011. (See Public Act 97-0616) The effective date of the change in the SIT law was January 13, 2011. (See Section 201(b)(10) of the ITA; Public Act 96-1496) Therefore, CUB concludes, the change in the SIT law that could trigger the amortization provision did not, in fact, occur after the effective date of the provision itself. Although the state corporate income tax rate itself changes in future years, those changes do not require any further changes in the law governing those rates. That is, the law that became effective January 13, 2011 includes those future changes in SIT rates.

CUB also maintains that Mr. Stafford's proposal to treat only the deferred income tax impact as an item that requires amortization produced results of having only an $827,000 reduction to deferred income taxes be reflected for operating expense and $3.310 million being credited to Rate Base in AIC's rebuttal filing. Because the tax change occurred in the year prior to AIC's opt-in to the formula rate, Mr. Stafford explains that AIC did not intend to continue the deferral and amortization of the credit in subsequent formula rate proceedings. Mr. Smith counters that the net impact of the SIT change does not exceed the statutory threshold of $3.7 million, since both the current SIT increase of $1.814 million must be considered along with the $4.137 net decrease to deferred state and federal income tax expense. As an accountant, Mr. Smith testified that the term "net" as used in his testimony meant "that the impact of the state tax law change on 2011 did not exceed the $3.7 million threshold for amortization that's provided for in the Act." (Tr. at 456) In opposition to Mr. Stafford's assertion, Mr. Smith explains, "this is a change in state tax law, and when you combine the increase in current SIT expense and a decrease in deferred income tax expense, one went up and the other went down, that net impact doesn't exceed the 3.7 million threshold that applies to Ameren." (Id. at 457) According to Mr. Smith, this is the correct treatment of the SIT change because "both of the items are the result of the change in the state tax law, so I think in this instance, you … have to combine them to evaluate whether they're above or below the 3.7 million." (Id.)

Moreover, Mr. Smith testifies that the impacts on deferred SIT expense related to the known changes in the SIT rate are annually recurring, and are not an isolated impact confined to calendar year 2011 but rather create additional annual reductions in 2012 through, at least, 2024. Given AIC's recalculation of its 2011 jurisdictional SIT expense for the difference between Illinois' 7.3% and 9.5% SIT rates, Mr. Smith also testifies that pursuant to the matching principle there should be consistency in the period used to calculate current and deferred income tax expenses. Instead, AIC seeks to use calendar year 2011 to calculate current SIT expense but only reflects one-fifth of the known and measureable impact of the SIT rate change. Instead of reflecting the effect as a one-fifth amortization, Mr. Smith concludes that the annual impact should be reflected in AIC's rate structure.

c. Staff Position

Staff supports the same adjustment concerning deferred SIT expense that AG/AARP and CUB recommend. Like the intervenors, Staff also accepts the savings amounts calculated in AIC Ex. 11.3. Thus, Staff concludes that the only contested issue on this topic is how to appropriately present these savings in the approved revenue requirement.

Staff recommends that the tax savings be reflected as a net reduction to income tax expense in the operating statement of $4.137 million rather than the amortized treatment reflected by AIC in AIC Ex. 11.2, Workpaper 5. Staff rejects the idea that since the calculation of deferred tax expense ($4.137 million) is greater than the $3.7 million threshold, Section 16-108.5(c)(4)(F) of the Act requires the amount to be recognized as a deferral subject to amortization. Staff points out that this section of the Act provides for unusual significant costs (credits) that occur in a calendar year to be spread over a longer period for recovery, such as storm expense. The tax credit resulting from the change in SIT is not, Staff points out, a credit that occurs in a single calendar year but is rather an impact that will be realized in future periods as the taxes that were deferred at the higher rate will be paid out at a lower rate when the state tax rate decreases. Even if Section 16-108.5(c)(4)(F) is found to apply to this issue, Staff agrees with AG/AARP witness Brosch's view that AIC's analysis does not consider the entire impact of the SIT rate change. (See AG/AARP Ex. 3.0 at 33)

d. AIC Position

AIC reports that the result of the SIT rate change is two-fold: first, the change results in a net increase in, or charge to, state and federal income tax expense of $1,813,717; second, due to the tax rate change not being permanent, the change results in a reduction, or credit, to 2011 deferred income tax expense of $4.137 million. Thus, AIC states that the increase in the SIT rate actually resulted in income tax savings, due to the fact that the tax rate change was not permanent. AIC understands that all of parties agree that (i) there is a reduction in deferred tax expense, and (ii) it should be reflected for ratemaking purposes. AIC also agrees that the only material dispute is how to reflect the tax savings amount for ratemaking purposes.

AIC argues that Section 16-108.5(c)(4)(F) requires the amortization of the deferred income tax expense of $4.137 million over five years, with one-fifth of the cost included in operating expense in the amount of $827,000 and the remaining four-fifths, or $3.310 million, of the credit included in rate base. AIC claims that this treatment is consistent with the charge for an incremental storm event that was deferred in AIC’s direct filing. AIC rejects the argument of Staff and intervenors that the deferred tax credit should be netted against the increase in current income tax expense (of approximately $1.8 million), which produces an amount less than the $3.7 million threshold in the statute for amortization. According to AIC, netting these amounts is not contemplated by the statute; AIC states that Section 16-108.5(c)(4)(F) requires “amortization over a 5-year period of the full amount of each charge or credit.” AIC maintains that the current tax increase and the deferred tax reduction are separate “charges or credits” and must be viewed separately, not as a net, for purposes of Section 16-108.5(c)(4)(F). Mr. Stafford attempts to explain that there are two key components of the tax rate change. The first is the change in the tax rate to 9.5%, which has an impact of less than $3.7 million and not subject to amortization. The second and distinct tax rate change is the tiered reduction from 9.5% to 7.3% in 2025 that impacts only deferred income tax for assets with amortizable lives extending beyond 2014. Mr. Stafford asserts that this tax rate change component exceeds $3.7 million. Because these two components are separate, AIC argues that they must be evaluated separately under the statute, and not “netted” as AG/AARP and CUB propose. AIC claims further that its treatment in this regard is consistent with the Commission’s Order in Docket No. 11-0721, in which the Commission authorized, per Section 16-108.5(c)(4)(F), amortization of an accrued credit amount for electric distribution tax over a five-year period, without netting the credits against current distribution tax expense. (See May 29, 2012 Order at 108)

AIC also disagrees with the Staff and intervenor argument that the SIT rate differences will affect deferred SIT expense annually, not only in 2011, but for each year, and so are not appropriate for amortization (unlike one-time significant annual charges like a storm expense). AIC maintains that its adjustment is limited to the impact on deferred income taxes in 2011. Accordingly, AIC indicates that the measured impact that is the basis for the amortization is actual 2011 income tax expense, as shown on the 2011 FERC Form 1, not some future year amount. Because the deferred tax amount is a credit "in the applicable calendar year" (2011), and exceeds $3.7 million in 2011, AIC claims that amortization is appropriate under the terms of the statute. AIC reiterates that this treatment is consistent with the treatment of electric distribution tax in Docket No. 11-0721, where the applicable year credit for which amortization was authorized was an accrual of the electric distribution tax credits for 2008-2010. (See May 29, 2012 Order at 106, 108) AIC states that Section 16-108.5(c)(4)(F) makes no provision for accounting for charges or credits in years other than the applicable calendar year. Charges or credits in those years, AIC continues, would be measured against the $3.7 million threshold and treated accordingly in those years.

e. Commission Conclusion

The Commission has reviewed the parties' arguments and understands that the only material dispute is how to reflect the tax savings amount for ratemaking purposes. The parties' positions focus in large part on the application of Section 16-108.5(c)(4)(F) of the Act. The Commission has considered this issue and concludes that Staff, CUB, and AG/AARP have properly applied the law for the reasons they offer. For purposes of this adjustment, the Commission will adopt Staff's calculations.

6. Section 9-227 Donations/Charitable Contributions

a. Staff Position

Staff recommends that ten of AIC's charitable contributions be disallowed, as reflected in Appendix A, Schedule 11 attached to Staff's Initial Brief. Staff argues that membership fees to tourism commission and economic development organizations are not donations because AIC receives a corporate benefit from making these donations. Staff explains that the corporate benefits received range from receiving member discounts to being involved in joint efforts to shape public policy and key issues affecting their businesses and their community. Staff reports that the membership benefits to AIC are explicitly stated on the websites of the economic development organizations. (See Staff Ex. 3.0R-C at 9-10)

In determining whether contributions are recoverable from ratepayers, Staff considers the donees' status under the Internal Revenue Code ("IRC"), 26 United States Code 1 et seq., as a Section 501(c)(3) organization. In addition, Staff considers whether AIC received or expected to receive benefits from the donations. Staff concludes that if a donor benefits when making a gift/donation, then the donation should not be recoverable from ratepayers. Staff provides this as a basic definition for a donation to be considered a charitable contribution. Staff maintains that ratepayers should not have to reimburse AIC for the cost of donations for which AIC received a benefit.

Although the Commission in its Order in Docket No. 12-0001 rejected the use of Section 501(c)(3) status as the sole filter for determining recoverability, Staff points out that the Commission's conclusion in that case did not address whether AIC received or expected to receive benefits from its donation. In addition, Staff observes that the home page of many of the economic development organizations' websites in which AIC is a member prominently display advertisements of members' products, services, and website links. Staff reports that the information available on these websites promotes benefits to members, encourages potential electronic commerce transactions, and fosters business connections. In Staff's opinion, this type of sales-related activity does not suggest that these organizations are primarily charitable or public welfare groups, but rather function as a forum to promote the business of its members.

As an example of its concerns, Staff references the website for the Greater Springfield Chamber of Commerce (http://www.gscc.org/join/benefits.asp). According to Staff, the website states the following:

> Membership in the Greater Springfield Chamber of Commerce offers significant opportunities to grow your business, hear from the region's prominent business and government leaders, and expand your contacts.

Staff believes that it is evident that corporations receive a benefit from being members in these types of organizations. What is not described, Staff continues, is the organization's charitable mission or how the public welfare benefits from the organization.

In response to AIC's claim that these economic development organizations enhance local communities by attracting new industry and jobs, and assist companies in relocating and expanding, Staff asserts that it is highly improbable that the vast majority of AIC ratepayers could identify any benefit they have enjoyed from these AIC donations. Moreover, based on the corporate tax structure policies of the State of Illinois and various other units of government,[2] Staff contends that it is likely that the economic development opportunities fostered by these organizations in their respective communities is done at the expense of the loss of economic development in other Illinois communities, some of which may also be in AIC's territory. As an example, Staff states that organizations such as the municipal chambers of commerce that AIC donated to often attract jobs away from another Illinois municipality, which may also be in AIC's service area. Staff reiterates that it is very difficult to see how this would benefit the public welfare of the state as a whole or even the more limited public welfare of those paying AIC rates.

[2] Staff references the Tax Increment Allocation Redevelopment Act (65 ILCS 5/11-74.4.1 et seq.), the Economic Development Project Area Tax Increment Allocation Act of 1995, (65 ILCS 110/1 et seq.), the Business District Development and Redevelopment Act (65 ILCS 5/11-74.3 et seq.), and the County Economic Development Project Area Tax Allocation Act (55 ILCS 85/).

Staff reports that the Commission has previously concluded that payments to economic development organizations disguised as charitable contributions should not be recovered from ratepayers. In these orders, Staff relates that the Commission explicitly found that it is not willing to blur the distinguishable categories of industry dues and charitable contributions. The Commission concluded in the cited orders that the specific contributions to economic and community development organizations at issue were more properly categorized as industry dues that should be shouldered by shareholders.

In the Order in Docket No. 05-0597, the Commission disallowed a $50,000 donation to the Illinois Manufacturers' Associations ("IMA") because the payment constituted a payment for lobbying or a political activity. The Commission stated:

> ComEd claims that this contribution was for the IMA's "Research on Education in Illinois" and that Staff's adjustment for this should be rejected. Staff argues that the invoice is clearly labeled a "Legislative Strategies" contribution. Section 9-224 of the Act (220 ILCS 5/9-224) prohibits including in any rate or charge any costs or payments for lobbying or political activity. Therefore, the Commission accepts Staff's recommended disallowance of $50,000.00. (July 26, 2006 Order at 101)

Likewise, in the Order in Docket No. 04-0442, the Commission upheld a Staff disallowance for an amount paid to the Danville Area Economic Council. The Commission found that the payment was within the category of dues and not charitable contributions. The Commission explained that:

> The first area of the adjustment concerns the amount paid to the Danville Area Economic Council. This type of adjustment also was at issue in Docket 03-0403. The Order entered in that case states:
>
>> The Commission is not willing to blur the distinguishable categories of industry dues and charitable contributions. The Order entered in 90-0169 squarely places the costs for industry association dues on the shareholders. See Order, 90-0169, at 65.
>
> The Commission finds that the payments to the Danville Area Economic Council are within the category of dues and not charitable contributions. The eventual public purpose, as alleged by Aqua, is insufficient to qualify the dues paid for recovery pursuant to Section 9-227. The Commission therefore holds that the adjustment proposed by Staff is proper for the payments to the Danville Area Economic Council. (April 20, 2005 Order at 31)

In the Order in Docket No. 03-0403, which concerned Consumers Illinois Water, the Commission adopted Staff's adjustment to charitable contributions because it lacked sufficient evidence to determine that the contributions to the community and economic development organizations were properly within the scope of Section 9-227. The Commission explained that:

> Neither party contends that the donations at issue are for "charitable scientific, religious or educational purposes." Instead, they are for community or economic development associations.
>
> * * *
>
> The Commission declines to presume that, at any given local unemployment rate, contributions to economic and community development organizations are necessarily for the public welfare. It is possible that such a contribution is made for a purpose that can not be recovered under Section 9-227. The Commission specifically notes, however, that it also does not establish any rule or presumption that contributions to economic and community development organizations may not be recovered under Section 9-227. Instead, a determination must be made on the evidence presented for each case. The utility has the burden to provide the evidence required to establish recoverability under this Section.
>
> * * *
>
> With only the basic information contained in Schedule C-7 and Company testimony regarding other donations not at issue here, the Commission lacks sufficient evidence to determine that the contributions to the community and economic development organizations are properly within the scope of Section 9-227. Accordingly, the Commission concludes that the amounts in question should be excluded from the cost of service in this case. (Cf. Order, 02-0690, at 21 (disallowing recovery of donations "which may or may not be allowable under the Act, but [due to the] lack of evidence, cannot be determined as such"). Accordingly, Staff's proposed reduction to charitable contributions is accepted. (April 13, 2004 Order at 18-19)

Another example in which the Commission concluded that dues to chambers of commerce and community organizations may not be characterized as charitable contributions is found in the Order in Docket No. 01-0432, which concerns Illinois Power Company:

> A significant component of Staff's argument on this issue is that IP will receive membership benefits in return for the dues payments in question. Notably, IP did not refute this assertion. The Commission concurs with Staff's recommended disallowance of $56,000 of chambers of commerce and community organizations dues. Since IP benefits from the payment of the dues, they may not be characterized as charitable contributions. Whether or not the IRS considers the organizations to which the dues payments were made not-for-profit is not at issue. (March 28, 2002 Order at 54)

Upon considering the cited dockets, Staff contends that the donations at issue in this proceeding clearly suffer from the same infirmities as those charitable contributions addressed by the Commission above and further do not meet the Commission's idea of a Section 9-227 "public welfare" donation as articulated in its Order in Docket No. 12-0001. Staff believes that at best, any alleged benefit to the public welfare is remote and tenuous. On the other hand, Staff argues that the benefits AIC enjoys from these donations are direct and clear. Staff recommends that the Commission accept Staff's proposed adjustment to remove from AIC's revenue requirement the donations to the ten economic development organizations because they are not legitimate charitable contributions.

b. AIC Position

AIC states that the basis for Staff's adjustment in this proceeding is the same basis rejected by the Commission in Docket No. 12-0001: the use of the recipient's federal tax status as a filter to exclude from rates the donations that utilities make to economic development organizations. AIC urges the Commission to reject Staff's adjustment consistent with its findings in Docket No. 12-0001. AIC contends that there are a number of fundamental flaws with Staff's use of a Section 501(c)(3) filter that have been exposed in both this proceeding and Docket No. 12-0001 that make the proposal simply unworkable and subject to abuse. First, AIC complains that Staff's insistence that the recipient organizations qualify and register for Section 501(c)(3) status as a "charitable" organization eligible to receive tax-deductible contributions grafts onto Section 9-227 of the Act a requirement that is not written into the law. Donations, AIC explains, are recoverable under Section 9-227 provided they are reasonable in amount and made "for the public welfare or for charitable, scientific, religious or educational purposes." AIC reports that the Commission previously found donations to be "for the public welfare" if they are "contributing to the general good of the public." (Docket No. 11-0721, May 29, 2012 Order at 98) In AIC's opinion, requiring every donation to be made for a "charitable" purpose to an organization that qualifies as a "charitable" organization under Section 501(c)(3) essentially writes the "for the public welfare" prong out of the law.

Additionally, AIC complains that the use of a Section 501(c)(3) filter ignores the fact that an organization can be tax-exempt under any number of provisions of the IRC. AIC states further that the use of a recipient organization's tax status as a disqualifying or qualifying factor ignores all of the other evidence provided by a utility in support of cost recovery of the donation. In AIC Ex. 14.1, AIC provided the name of each recipient, each recipient's Federal Employer Identification Number, a description of the nature and purpose of the recipient, the use of the donation, and the identified Section 9-227 categories for each donation. AIC argues that this is actual data that can be used to objectively determine on a case-by-case basis whether a particular donation should be recovered. AIC contends that the insistence on the use of a Section 501(c)(3) filter ignores the characteristics of the individual donation and AIC witness Pagel's testimony. The difference, AIC continues, in the tax-exempt status of a Section 501(c)(3) and, for instance, a Section 501(c)(6) organization should not dictate whether a donation is recoverable under Section 9-227 of the Act.

AIC argues as well that the fact that a donation to a Section 501(c)(3) organization is tax deductible, or that Section 501(c)(3) organizations are subject to restrictions on legislative and political activities, are meaningless distinctions. If a particular donation contributes to the general good of the public in the communities that AIC serves, AIC insists that it should be recoverable, regardless of whether it is deductible to the donor or the recipient organization is tax-exempt. According to AIC, the context of the individual donation should control the analysis, not the federal tax status of the recipient organization. Moreover, the fact that Section 501(c)(3) organizations are restricted in their lobbying is not in AIC's opinion evidence that donations to non-Section 501(c)(3) organizations somehow are being used for lobbying purposes. AIC asserts that there is no evidence that indicates these local economic development organizations are using AIC's donations to fund lobbying activities.

AIC also maintains that the categorical exclusion of donations to local economic development organizations ignores the benefits that these groups provide. Ms. Pagel testifies that these organizations seek to nurture the development of communities in AIC's service territory. She states that they support initiatives to strengthen and enhance local economies, identify present and future workforce needs, attract new industry and jobs, and assist companies in relocating or expanding. That they may promote a business interest does not, in AIC's view, mean they do not serve a public need or provide a community benefit. AIC relies on the Commission's finding in Docket No. 11-0721 that donations to local economic and community development organizations are recoverable operating expenses that just happen to "serve a public need that is different from serving the needy and the poor." (Order at 98)

Lastly, AIC insists that Staff's claim that donations to these groups deliver only "corporate benefits" to AIC is neither supported by any record evidence nor a credible theory. AIC maintains that the standard for recovery is not whether the donor receives any ancillary benefits by virtue of the donation. In any event, AIC argues that the record contains no evidence of it having received any benefit from any of its payments to the local economic development organizations or that its payments were membership dues. According to AIC, Staff's focus should be on the purpose and use of the specific donation to the individual recipients, not on crafting a results-driven test to convince the Commission to exclude an entire category of donations.

c. Commission Conclusion

The Commission has considered the arguments of Staff and AIC and is intrigued by Staff's citation to past orders and argument regarding benefits to AIC. But because the record lacks any evidence of AIC having made the payments as membership dues or having received any benefits, the Commission is not prepared to consider the contributions similar to those at issue in the dockets cited by Staff. Perhaps with additional evidence a different outcome would be reached. That being said, the

Commission will not adopt Staff's proposed adjustment concerning charitable contributions.

Information concerning benefits associated with charitable contributions should, if it is not already, be addressed in the workshops taking place in Docket No. 12-0457. The workshops should also consider whether customers or the recipients of such donations are aware of their source. To promote transparency and customer understanding of the ratemaking process, participants in the workshops should discuss an appropriate means of disclosing that Section 9-227 of the Act permits utilities to recover charitable contributions from customers. Ameren is a combined utility with gas and electric service territories that overlap, but are not the same, and the Commission is concerned that the information received on charitable contributions allocates those contributions to the electric and gas utilities on a static basis without regard for programs with a set geographical focus. In cases where such programs benefit just ratepayers of the gas utility, but not electric utility (e.g., within the city limits of Springfield), it may not be appropriate to recover those costs from electric customers. The Commission further requests that in the workshops taking place in Docket No. 12-0457 as well as in any proceedings conducted prior to the conclusion of that docket, care is taken to ensure that charitable contributions are not automatically assigned to both the gas and electric utilities.

VII. OPERATING REVENUES

The only contested issue pertaining to operating revenues in this matter concerns the proper treatment of late payment revenues. Late payment charges are added to ratepayers' bills when payments have not been received by bill due dates. Electric Service Schedule Ill.C.C. No. 1, Original Sheet No. 3.018 provides for a ". . . late payment charge equal to 1.5% per month" to be assessed "on any amount considered past due," as more fully described in the tariff.

Just as they did in Docket No. 12-0001, AG/AARP and CUB recommend that 100% of late payment revenues be considered subject to this Commission's jurisdiction and not subject to any revenue-based allocation factor that would allow AIC shareholders to retain a portion of such revenues. Although the Commission adopted AG/AARP's position in Docket No. 12-0001, AIC continues to object to the adjustment in this docket. While Staff supported AIC's position in Docket No. 12-0001, Staff now asserts that nothing has changed since that proceeding so there is no reason to deviate from the Commission's earlier conclusion on the treatment of late payment revenues.

The Commission appreciates the presentations of the parties regarding this issue and, particularly, understands AIC's desire to reserve its rights to further pursue this matter. Nevertheless, the Commission rejects AIC's position for two reasons. First, the purpose of this proceeding is to update inputs into AIC's existing formula rate which was established in Docket No. 12-0001. The Act specifically prohibits the Commission from modifying the formula rate itself, which is intended to protect both AIC and ratepayers. Second, even if this were an appropriate forum to consider modifying AIC's formula rate, AIC has failed to identify any change in law or facts that justify deviating from the Commission's decision in Docket No. 12-0001. Accordingly, the Commission adopts the AG/AARP adjustment on this issue.

VIII. RATE OF RETURN

The parties agree that Rate MAP-P properly applies an authorized rate of return on common equity of 9.71%, which equals the monthly average 3.91% 30-year United States Treasury bond yield during the subject year plus 580 basis points, as set forth in Section 16-108.5(c)(3) of the Act. They also agree that Section 16-108.5(c)(2) provides that the formula rate approved by the Commission shall "[r]eflect the utility's actual capital structure for the applicable calendar year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law." Although Section 16-108.5 effectively disconnects capital structure from rate of return, Staff is still concerned that AIC has overestimated the proportion of common equity in its capital structure. AIC and Staff propose the following capital structures reflecting their respective recommendations:

	AIC	Staff
Common Equity	54.85%	51.00%
Preferred Stock	1.65%	1.64%
Long-Term Debt	43.50%	47.36%
Short-Term Debt	0%	0%
	100.00%	100.00%

A. Uncontested Issues

1. Construction Work in Progress Accruing Allowance for Funds used During Construction Adjustment

Staff recommends an adjustment to the average balances of long-term debt, preferred stock, and common equity to remove the portions that the AFUDC formula assumes is financing CWIP. In light of the Commission's decision on this issue in Docket No. 12-0001, AIC will not challenge Staff's position for purposes of this case. The Commission's conclusion on this issue in Docket No. 12-0001 provided:

> The Commission disagrees with AIC’s position that the dollar values reflected in its capital structure are meaningless. While under current circumstances, Staff’s adjustment will not alter the ratios or rate of return, the Commission finds merit in ensuring that the capital structure is measured accurately. Consistent with Docket No. 11-0721, the Commission adopts Staff’s adjustment on this issue. (September 19, 2012 Order at 111)

The Commission sees no reason to deviate from its conclusion in Docket No. 12-0001 on this issue and adopts Staff's position for this proceeding as well.

2. Cost of Short-Term Debt, including Cost of Credit Facilities

Staff calculates the cost of credit facilities for AIC using the costs of the September 10, 2010 credit facility that the Commission authorized in Docket No. 11-0282, which were adjusted pursuant to Section 9-230 of the Act. To calculate the weighted cost of credit facility fees, Staff divides AIC's total bank commitment fees of $2,815,432 by total capitalization. Thus, Staff adds 8 basis points to AIC's rate of return on rate base. AIC accepts Staff's position based on the Commission's Order in Docket No. 12-0001, which concluded:

> Consistent with its past decision in Docket No. 11 0282, the Commission will adopt Staff's adjustment concerning credit facilities. As previously found by the Commission, AIC has failed to demonstrate that it is certain, or even likely, that the fee rate schedule for the Illinois credit facility would have been exactly the same if it had been negotiated totally independently from the other two credit facilities that Ameren and its subsidiaries entered into during July 2010. (September 19, 2012 Order at 131)

The Commission sees no reason to deviate from its conclusion in Docket No. 12-0001 on this issue and adopts Staff's position for this proceeding as well.

B. Contested Issues

1. Year-End versus Average Capital Structure

Staff calculated AIC's average 2011 capital structure as follows: 53.26% common equity, 1.64% preferred stock, 45.10% long-term debt, and 0% short-term debt. Staff recommends using AIC's average capital structure for the same reasons it offers in Docket No. 12-0001. AIC continues to argue that use of its year-end capital structure is required by Public Acts 97-0616 and 97-0646. The Commission considered the same issue in Docket No.12-0001 and concluded the following:

> Section 16-108.5(c)(2) requires that the formula rates "[r]eflect the utility's actual capital structure for the applicable calendar year, excluding goodwill, subject to a determination of prudence and reasonableness consistent with Commission practice and law." The Act does not specify exactly how the "actual capital structure" is to be determined. The Commission finds Staff's arguments for how to determine AIC's capital structure persuasive. Staff's method is consistent with Commission practice and law and mitigates the risk of manipulation. AIC's claim that Staff uses 2009 data is not well taken given that the December 31, 2009 balances used by Staff are identical to opening January 1, 2010 balances. AIC's argument is also disingenuous in light of its own use of December 31, 2009 data for calculating short-term debt balances. Accordingly, the Commission adopts Staff's proposed average capital structure

methodology with the knowledge that it will more accurately reflect AIC's actual capital structure. (September 19, 2012 Order at 110)

The Commission appreciates the presentations of the parties regarding this issue and, particularly, understands AIC's desire to reserve its rights to further pursue this matter. Nevertheless, the Commission rejects AIC's position for two reasons. First, the purpose of this proceeding is to update inputs into AIC's existing formula rate which was established in Docket No. 12-0001. The Act specifically prohibits the Commission from modifying the formula rate itself, which is intended to protect both AIC and ratepayers. Second, even if this were an appropriate forum to consider modifying AIC's formula rate, AIC has failed to identify any change in law or facts that justify deviating from the Commission's decision in Docket No. 12-0001. Accordingly, the Commission adopts Staff's use of average capital structure, subject to the adjustments set forth below.

2. Common Equity Ratio

AIC and Staff raise arguments on this issue very similar, and in some cases identical, to those they raised in Docket No. 12-0001. (See generally Docket No. 12-0001, September 19, 2012 Order at 124-127) Although Staff observes in the present docket that the implementation of formula rates have affected AIC's credit quality favorably, Staff witness Phipps evaluated AIC's current capital structure under the traditional regulatory framework under which it was developed. AIC proposes using a December 31, 2011 capital structure, which comprises 54.85% common equity. Staff measured a 53.26% average 2011 common equity ratio. Staff contends that neither of those capital structures would be appropriate for setting rates because both produce a rate of return that would violate Section 9-230 of the Act given that Ameren, AIC's parent company, had an average 2011 common equity ratio of 51.05% over the same measurement period. Because Illinois law bars the Commission from including any increased cost of capital resulting from a public utility's affiliation with any unregulated or non-utility companies, Staff insists that an adjustment to AIC's capital structure is necessary.

In comparing AIC's capital structure to that of its parent Ameren, Staff also notes that Standard & Poor's Ratings Services ("S&P") indicates that AIC's regulated operating risk is lower than that of Ameren. Staff points out that Ameren's credit rating reflects riskier generation operations. Given the fact that AIC has lower operating risk than Ameren, Staff contends that AIC should be able to maintain more financial risk than Ameren to achieve the same stand-alone credit rating as Ameren.

In response to AIC's claim that no adjustment is warranted, Staff points out that AIC has a clear incentive to use a capital structure with an excessive amount of common equity. Excessive common equity would allow AIC a greater return on its capital while leaving ratepayers to shoulder the increased costs of capital for AIC. Staff points out that courts recognize that the capital structure of a regulated utility can be manipulated to include excessive common equity to inflate the rate of return. (See Citizens Utility Board v. Illinois Commerce Commission, 276 Ill. App. 3d 730, 744 (1st

Dist. 1995)) Staff insists that it need not show actual manipulation by AIC (beyond what it has already discussed) because under Section 9-201 of the Act, the burden is on AIC to prove the justness and reasonableness of its proposals.

Staff recognizes AIC's concern that a lower, imputed common equity ratio may lead to rating agencies downgrading AIC's credit risk. Staff suggests, however, that AIC's expression of concern may not be sincere. Staff notes that AIC opposes Staff's proposed imputed capital structure even though it once made dividend payments that reduced one of Moody's Investors Service, Inc.'s ("Moody's") credit metrics to junk rating level.

For these reasons, Staff proposes using an imputed capital structure that comprises 51.00% common equity, 1.64% preferred stock, and 47.36% long-term debt. Staff's proposed imputed capital structure for AIC substitutes Ameren's average 2011 common equity ratio of 51.00% for AIC's average 2011 common equity ratio of 53.26%. Staff used the actual proportion of preferred stock in AIC's average 2011 capital structure. To calculate AIC's long-term debt ratio, Staff added AIC's average 2011 preferred stock ratio and the imputed 51.00% common equity ratio (1.64% + 51.00% = 52.64%) and then subtracted that from 100.00% to derive the long-term debt ratio of 47.36% (100.00% - 52.64% = 47.36%).

In addition to comparing AIC's capital structure to that of its parent company, Staff compared AIC's capital structure to those of other electric companies. Moody's categorizes debt securities based on the risk that a company will default on its interest and principal payment obligations. The resulting credit rating reflects both the operating and financial risks of a utility. Staff reports that in its June 13, 2012 credit opinion, Moody's gives AIC a corporate credit rating of Baa2. Moody's states, "[o]bligations rated Baa are subject to moderate credit risk. They are considered medium grade and as such may possess certain speculative characteristics." Staff also states that based on data from S&P's Utility Compustat database, the average common equity ratio equals 47.02% for utilities in the electric industry with an S&P credit rating in the BBB range. Staff's proposed common equity ratio of 51.00% indicates a lower degree of financial risk than the average BBB rated electric utility company.

As it did in Docket No. 12-0001, AIC argues that its actual year-end capital structure for the historical period reported in FERC Form 1 for 2011 should be used. AIC acknowledges the Spring 2012 Moody's credit opinion regarding the formula rate process that Staff relies upon, but maintains that this alone is not an appropriate basis for using an imputed capital structure. AIC argues that a critical problem with Staff's position is its reliance upon a credit opinion from 2012 as justification to adjust the 2011 capital structure, with no reference to reports from the actual period at issue. Because the 2012 credit opinion was issued after the applicable calendar year of 2011 and is only applicable to future formula rate proceedings, AIC insists that the record is void of any analytical basis for Staff's adjustment in the present docket.

AIC also recognizes that Section 9-230 requires the Commission to remove the effects of incremental risk or cost that result from affiliation from the rate of return, but contends that Staff does not provide any analytical support demonstrating how and to what extent any affiliate has negatively impacted AIC's risk or cost of capital. Although S&P references the decline in purchase power prices affecting AIC's merchant generating affiliate, AIC states that neither Moody's nor Fitch Ratings Ltd. reference its unregulated generation affiliate. AIC adds that it has not experienced any incremental risk or cost by virtue of its affiliate relationships.

The Commission appreciates the presentations of the parties regarding this issue and, particularly, understands AIC's desire to reserve its rights to further pursue this matter. Notably, in light of the recent discussion of this issue in Docket No. 12-0001, not all of the arguments made by AIC and Staff are summarized here. Having considered those arguments set forth above as well as those elsewhere in the record, the Commission rejects AIC's position and adopts Staff's position. Individually, the concerns raised by Staff are insufficient to win the day. But cumulatively, the Commission is persuaded that Staff's imputed capital structure is appropriate. The Commission finds that AIC has lower operating risk than Ameren and now enjoys a more favorable regulatory environment under Public Acts 97-0616 and 97-0646. The Commission also notes that AIC has failed to identify any change in law or facts that justify deviating from the Commission's decision in Docket No. 12-0001. Accordingly, the Commission adopts Staff's imputed capital structure.

3. Common Equity Balance - Purchase Accounting

In the event the Commission does not adopt its proposed imputed capital structure, Staff states that the Commission would need to remove all purchase accounting adjustments, including goodwill, when calculating AIC's common equity balance in accordance with its Order in Docket No. 04-0294. AIC denies that any such adjustment is necessary regardless of whether Staff's imputed capital structure is adopted. In light of the Commission's adoption of Staff's imputed capital structure above, the Commission finds that no action need be taken regarding purchase accounting.

IX. COST OF SERVICE AND RATE DESIGN

Staff believes the embedded cost of service study, cost allocation to classes, revenue allocation, and rate design methodologies in this proceeding should be consistent with the methodologies approved by the Commission in Docket No. 12-0001. To ensure consistency between these two dockets, Staff recommends AIC file revised cost of service study ("COSS"), revenue allocation schedules, and rate design and bill impact schedules that incorporate the COSS, revenue allocation and rate design methodologies approved in Docket No. 12-0001. (Staff Initial Brief at 44-45) AIC has agreed to Staff’s recommendation and will file with its compliance filing revised COSS, revenue allocation schedules, and rate design and bill impact schedules that incorporate the COSS, revenue allocation, and rate design methodologies approved in

Docket No. 12-0001. AIC notes that providing bill impact schedules goes beyond information normally provided in a compliance filing. Because rate design is not at issue in this proceeding and will not change, AIC updating prices within the bill impact schedules can be accommodated within the compliance filing timeline. (AIC Initial Brief at 68-69)

X. FORMULA RATE TARIFF

A. Year-End versus Average Rate Base

1. AIC Position

AIC recognizes that in Docket No. 12-0001, the Commission determined that an average rate base should be used for formula rate reconciliation. AIC argues that this decision cannot be considered determinative at this time in this docket. AIC also contends that the record in this case is different from that in Docket No. 12-0001 and supports a different result. AIC appealed the Commission's conclusion on this issue on October 26, 2012. In order to pursue appeal on this issue, in Docket No. 12-0001 or this Docket, AIC believes it must continue to contest the issue to preserve its arguments.

AIC notes that it has extensively briefed this issue previously and maintains that use of a year-end rate base for reconciliation should be approved. AIC has three primary arguments why it believes use of a year-end rate base for reconciliation is appropriate. First, AIC insists that the plain language of the EIMA requires use of a year-end rate base for reconciliation. To the extent interpretation is required, AIC argues that the fact that the EIMA does not refer to the use of averages when referring to reconciliation rate base (but has specified use of averages elsewhere in the EIMA, and routinely used the concept of annual averages throughout the Act) is dispositive. Second, AIC argues that use of a year-end rate base for reconciliation reflects appropriate ratemaking policy. And finally, AIC contends that it would be adversely impacted by the use of a year-end reconciliation rate base.

2. AG/AARP Position

Because AIC retains the right to seek rehearing on this and other issues decided in Docket No. 12-0001, AG/AARP, for purposes of preserving its arguments in support of the use of an average rate base in calculating reconciliation amounts, briefly summarize the reasons why they believe the Commission’s decision in Docket No. 12-0001 was the correct one on this issue. (See AG/AARP Initial Brief at 51-53) AG/AARP state that the formula for the reconciliation of the revenue requirement will only represent actual costs if average, not year-end rate base is used. According to AG/AARP, if AIC’s revenue requirements are now to be annually trued-up so as to fully recover jurisdictional actual incurred costs, there is no need to address regulatory lag through use of a year-end rate base. AG/AARP assert that traditional test-year regulation involves setting utility rates that remain unchanged until the “next” rate case is filed, causing regulatory lag to exist when cost changes occur between test year rate cases. In AG/AARP's view, regulatory lag concerns are completely mitigated by the new formula ratemaking regime, where AIC will be made “whole” with interest for changes in all of its actual jurisdictional costs incurred to provide delivery services in Illinois. AG/AARP say the reconciliation true-up with interest puts AIC in exactly the same economic and financial position that it would be if all of the costs in the year being reconciled were recovered contemporaneously. They contend that when the formula-based revenue requirements, which are inclusive of projected net plant in service additions, are trued-up through the reconciliation process to actual cost levels, any revenue requirement variances are allowed interest charges to be sure that regulatory lag imposes no financial consequences on AIC. In this new regulatory environment, AG/AARP insist that there is no need for the Commission to permit the use of year-end rate base as a remedy for regulatory lag.

3. CUB Position

CUB states that the Commission found in both Docket Nos. 11-0721 and 12-0001 that under the EIMA, using an inflated rate base could result in substantial over-recovery from ratepayers. CUB says the Commission agreed that if the General Assembly intended to include only year-end rate base balances in the reconciliation, it would have so stated – and it did not. In that case, CUB claims the Commission recognized that merely using year-end rate base assumes that a participating utility’s rate base is the same on January 1 as it is on December 31, and that is clearly not the case. CUB believes the Commission undertook a thorough analysis of statutory construction, and found that using an average year rate base in the formula rate reconciliation is the most accurate interpretation of the statute.

CUB claims the difference between using a year-end rate base and the average rate base for the applicable calendar year can have a significant impact on the results. To illustrate this point, CUB provided an illustration that assumes the utility had jurisdictional rate base investment of $2.0 billion on January 1 and $2.12 billion on December 31 of the calendar year, that the investment had been added ratably during the calendar year, and that the amount of actual net operating income for the year was approximately $190 million. CUB argues that where the utility’s rate base is growing significantly, as will likely be the case under the EIMA scheme, the distortion in the measurement of results for the applicable calendar period can become quite large. CUB believes this result is untenable and contrary to the plain reading of the Act.

CUB also disputes AIC's claim that the purpose of EIMA is to eliminate regulatory lag (and that this Commission policy frustrates that objective). CUB says the phrase “regulatory lag” is not even present in EIMA. According to CUB, the purpose of the formula rate legislation was not to eliminate regulatory lag as much as possible, or even to provide a participating utility with the greatest and earliest possible recovery. Rather, CUB says EIMA articulates the General Assembly’s desire to encourage the modernization of the state’s electric grid, and found that regulatory reform measures that increase predictability, stability, and transparency in the ratemaking process were needed to promote that investment. CUB believes the Commission correctly noted that the statute clearly contemplates some lag involved in the reconciliation process and it compensates utilities subject to it by allowing them to receive interest. CUB contends that requiring that rate base be calculated based on average year rate base rather than year-end rate base ensures that rates will be predictable, stable, and transparent, and ensures that only the utility's actual costs are recovered from ratepayers. CUB asserts that this new regulatory scheme fully compensates the utility for any regulatory lag by allowing interest to accrue on the reconciliation balance.

4. Staff Position

In its Reply Brief, Staff notes that the Commission issued its Order in Docket No. 12-0001, establishing the structure and protocols for AIC's performance based rate tariff (Rate MAP-P), pursuant to Section 16-108.5 of the Act. Staff contends that Docket No. 12-0293, an annual update proceeding, initiated pursuant to Section 16-108.5(d), has but one purpose: to update the cost inputs to the performance-based formula rate for the applicable rate year and the corresponding new charges. Staff argues that any arguments as to the structure or protocols of Rate MAP-P set in Docket No. 12-0001 should be disregarded as they are not applicable to this proceeding.

Staff believes that whether the record in this case is different from that in Docket No. 12-0001 is irrelevant, because these issues have been resolved in the initial formula rate proceeding and cannot be re-litigated each year. Staff also notes that in Docket No. 11-0721 on rehearing, the Commission confirmed that the appropriate reconciliation rate base was an average rate base, the appropriate interest rate on over/under reconciliation balances is a short-term debt cost rate, and that an average capital structure should be used for purposes of the formula rate reconciliation.

5. Commission Conclusion

The Commission appreciates the presentations of the parties regarding this issue and, particularly, understands AIC's desire to reserve its rights to further pursue this matter. Nevertheless, the Commission rejects AIC's position for two reasons. First, the purpose of this proceeding is to update inputs into AIC's existing performance-based formula rate which was established in Docket No. 12-0001. The Act specifically prohibits the Commission from modifying the performance-based formula rate itself, which is intended to protect both AIC and ratepayers. Second, even if this were an appropriate forum to consider modifying AIC's performance-based formula rate, AIC has failed to identify any change in law or facts that justifies deviating from the Commission's decision in Docket No. 12-0001.

B. Interest Rate on Under/Over Reconciliation Balances

1. AIC Position

As with reconciliation rate base, AIC recognizes that in Docket No. 12-0001, the Commission determined that a short-term debt cost rate should be used for reconciliation balances. AIC, however, believes that the issue is not final while AIC (and ComEd) pursue appeal on this issue. There four primary reasons AIC believes the Commission should set the reconciliation interest rate at its WACC. First, AIC notes that its appeal of the Commission's contrary decision in Docket No. 12-0001 has yet to be resolved. Second, AIC also argues that the decision in Docket No. 12-0001 is based on the incorrect premise that reconciliation balances are incurred over less than 12 months, while AIC claims they are incurred and then eliminated over a two year period, and are not properly characterized as short-term obligations. Third, AIC also suggests that use of the WACC would benefit customers if there are over-collections to be refunded. Finally, AIC claims the record in this case is different from that in Docket No. 12-0001 and supports a different result.

AIC argues that the WACC is the only proposed interest rate that complies with the statute because Section 16-108.5(c)(1) directs the Commission to allow a participating utility to recover the full cost of providing delivery services. AIC asserts that the WACC, which is what it actually pays for capital, is the only interest rate that will fully compensate AIC for the capital that was employed in the event of under collection. By deeming AIC to have financed this significant portion of its capitalization solely with debt, as all of the other reconciliation interest proposals do, AIC asserts that these proposals would shift the overall capital structure financing AIC’s operations in direct contravention of the directive in Section 16-108.5(c)(2) that the formula rate reflect a utility’s actual capital structure, unless shown to be unreasonable or imprudent.

AIC contends that the use of a short-term debt rate would not compensate AIC for its actual costs of accessing capital in the markets to fund investments required under the statute. AIC says it effectively would require AIC to alter its capital structure to fund reconciliation amounts with a certain mix of debt, irrespective of: the consequences of using only debt on AIC’s financial condition and credit ratings; whether such funding is prudent; and whether such funding is practicable.

In AIC's view, the Commission based its finding in Docket No. 12-0001 on a faulty assumption that reconciliation amounts do not represent or require permanent financing, and that they would either displace or require only short-term debt. AIC argues that reconciliation amounts are not short-term because short-term debt is debt issued for a period of less than one year. According to AIC, reconciliation amounts will not be recovered or refunded within one year. Under the protocols laid out in the EIMA, AIC says an under-recovery experienced in Year 1 will be the subject of an update filing in Year 2 and will be reflected in rates in Year 3. AIC says any under-recovery in Year 1, will not be fully recovered until the end of Year 3, meaning that the recovery period is two years. AIC believes the Commission is requiring that an investment with a life beyond one year be funded with debt issued for less than one year.

2. AG/AARP Position

According to AG/AARP, the issue of what rate of interest should be applied to reconciliation balances/credits to be used in the formula rate was decided in Docket No. 12-0001 and need not be re-litigated. AG/AARP believe Section 16-108.5(d) of the Act does not permit the Commission to tinker with the formula rate structure and protocols established in a utility's first formula rate proceeding. In AG/AARP's view, principles of statutory interpretation support rejection of AIC's proposal that a WACC interest rate be applied to the reconciliation balance/credit. AG/AARP also believe the Commission should reject application of AIC's WACC as the reconciliation balance interest rate is that AIC failed to provide evidence that the WACC was the appropriate compensation for the time value (a maximum two-year period) of money.

3. CUB Position

CUB states that this is the third docket in which the Commission is faced with the question of what interest rate/carrying cost to apply to a reconciliation balance under the EIMA formula rate scheme. According to CUB, in each of these dockets, the facts are substantially similar and the law is the same. In each of the two initial formula rate dockets in which the Commission issued a ruling on the issue and in the Order on Rehearing in Docket No. 11-0721, it rejected the utility's request to apply its respective WACC, which would have provided each utility a full equity return including long-term debt on a short-term balance spanning from one to two years.

CUB believes AIC should recover only what any under-recovered balance actually cost AIC if it had to get short-term financing elsewhere to cover the shortfall. CUB proposed that AIC's under-collections should be computed at a debt-based rate that corresponds with the one- to two-year reconciliation balance recovery period. CUB supports application of a short-term interest rate to AIC's under-collected reconciliation balance.

CUB argues that the record demonstrates that over-collected reconciliation balances should be treated differently. CUB says that under EIMA, AIC will be responsible for developing the amount of its projected plant additions for each year as well as managing the actual capital expenditures, and could thus produce over-collections simply by over-projecting such plant additions and subsequently managing actual capital expenditures to a lower level. CUB believes the Commission should acknowledge that both the projected level and the actual level of expenditures are heavily under the direct influence of AIC management. CUB contends that the control and discretion exerted by AIC management on not only budgeted capital expenditures but also on the level of actual expenditures subsequently made, and thus the ability to influence and manage whether there are under- or over-collections alone should be sufficient to justify and require the imposition of different carrying charges on over- and under-collections. CUB insists that requiring a higher interest rate for over-collections is therefore reasonable and principled and will provide an appropriate and necessary deterrent to AIC to discourage it from making intentional over-projections of plant additions or subsequently deciding to under-spend.

CUB believes that using AIC's WACC on over-collections assures that ratepayers will be compensated for providing excess funds to the utility under the formula rate plan (as measured by the over-collection) at a financing rate that is at least equal to the financing rate that the utility charged to ratepayers, which has in part produced those over-collections. CUB argues that there is ample legal, factual, and policy justification to apply AIC's WACC to the over-recovered reconciliation balance that exists in this proceeding. Finally, CUB recommends the Commission require that the interest rate on the reconciliation balance is calculated on a net of tax basis.

4. Commission Conclusion

The Commission appreciates the presentations of the parties regarding the appropriate interest rate to be earned on reconciliation balances and, particularly, understands AIC's desire to reserve its rights to further pursue this matter. Nevertheless, the Commission rejects AIC's position for two reasons. First, the purpose of this proceeding is to update inputs into AIC's existing performance-based formula rate which was established in Docket No. 12-0001. The Act specifically prohibits the Commission from modifying the performance-based formula rate itself, which is intended to protect both AIC and ratepayers. Second, even if this were an appropriate forum to consider modifying AIC's performance-based formula rate, AIC has failed to identify any change in law or facts that justifies deviating from the Commission's decision in Docket No. 12-0001.

XI. OTHER ISSUES

A. Original Cost Determination

AIC requests that the Commission approve an original cost of electric plant in service as of December 31, 2011, before adjustments for projected plant additions, of $5,023,011,000. Staff recommends that the Commission approve AIC's request for an original cost finding. Staff also requests that if the Commission makes any additional adjustments to plant, those adjustments should also be reflected in the original cost determination. Therefore, Staff recommends the Commission include the following language in the Findings and Ordering paragraphs of its order in this proceeding:

> the Commission, based on AIC's proposed original cost of plant in service as of December 31, 2011, before adjustments, of $5,023,011,000, and reflecting the Commission's determination adjusting that figure, unconditionally approves $5,023,011,000 as the composite original cost of jurisdictional distribution services plant in service as of December 31, 2011.

AIC does not oppose the inclusion of this language in the order in this case. The Commission finds this proposal to be reasonable and it is hereby adopted.

B. Uncollectibles Expense

Staff recommends that the agreement reached between Staff and AIC in Docket No. 12-0001 regarding uncollectibles expense be carried forward into this proceeding. In Docket No. 12-0001, Staff proposed and AIC accepted certain revisions to Schedule FR A-1REC and tariff language modifying Rider EUA - Electric Uncollectible Adjustment for the conversion to the net write-off method also agreed to by AIC. AIC did not reflect any of those changes in the filing in this proceeding; however, AIC is willing to agree to Staff's recommendation only if the revisions are accepted by the Commission in its order in Docket No. 12-0001. As the Commission adopted this agreement in its Order in Docket No. 12-0001, this issue is not contested. AIC indicates that Schedule FR A-1REC reflects the changes agreed to by AIC and those ordered by the Commission in Docket No. 12-0001. The Commission finds this agreement to be reasonable and it is hereby adopted.

C. Coordination with Docket No. 12-0001

Staff recommends that any conclusions in the final order in Docket No. 12-0001 regarding AIC's performance-based rate structure and protocols be reflected in the conclusions in the final order in this proceeding. AIC says it could provide formula rate schedules in this proceeding that conform with the final approved formula templates in Docket No. 12-0001 within a reasonable period after the Commission's order is issued in Docket No. 12-0001, and that preparation of the conformed formula rate template schedules could begin after AIC finalizes its formula rate template for its compliance filing in Docket No. 12-0001.

AIC originally stated it could, using best efforts, submit conformed formula rate revenue requirement schedules within this proceeding no later than October 1, 2012. Staff accepted AIC's projected submittal date. AIC's compliance filing in Docket No. 12-0001, however, will not be made until October 4, 2012. Therefore, AIC says submission of conforming schedules will take place as soon as reasonably practical after October 4. AIC says it will provide the conforming schedules requested by Staff to all parties on October 8, 2012.

Staff also recommends that when AIC provides the conformed formula rate schedules, the record be left open to allow the parties the opportunity to review the conformed formula rate schedules and provide a response that offers a revised position, if necessary. AIC accepts this recommendation as reasonable.

The Proposed Order concluded that this issue is not contested and that there is nothing for the Commission to deal with in this proceeding. In its Brief on Exceptions, Staff complains that, thus far, AIC has failed to follow through on its agreement to provide the conformed schedules it agreed to provide. As a result, Staff requests that the Commission admonish AIC for its failure to provide the promised information. It appears to the Commission that Staff's concern about AIC's failure to provide the promised information may have some validity. On the other hand, the Commission notes that Staff raises this concern for the first time in its Brief on Exceptions. Neither Staff's Initial Brief nor its Reply Brief suggest that it had any concerns with this issue. Given that AIC has not had an opportunity to respond to Staff's concerns, the Commission is not inclined to issue any specific admonishment on this issue. The Commission will generally state, however, that it expects all parties to follow through with their commitments.

D. Allowance for Funds Used During Construction Rate - Plant Balances

Staff recommends that the Commission order AIC to recalculate its AFUDC rate for all periods inappropriately impacted by the inclusion of acquisition adjustments and/or goodwill included in the equity balance and then make corresponding adjustments to affected utility plant accounts and related accounts. AIC says Staff's recommendation is similar to an order issued by FERC this year.

AIC says it has sought rehearing of the FERC order in question. AIC does not concede that the AFUDC rate has been improperly calculated, that a recalculation is required or that periods have been inappropriately impacted. Further, AIC does not concede that a recalculation of the AFUDC rate is legally permissible or is required for setting Illinois jurisdictional distribution rates.

AIC does agree with Staff that there is insufficient time within the record of this case to fully develop this issue and that AIC will address the issue of whether its AFUDC rate is improperly impacted by goodwill in its equity balances in its direct testimony in the next formula rate case. Staff does not object to this proposal. It appears that AIC and Staff agree that it is best if the Commission defers ruling on this issue until a future proceeding, which the Commission finds reasonable.

E. Reporting Plant Additions Pursuant to Section 16-108.5(b)

Staff recommends the Commission include a statement in its order in this proceeding that identifies the incremental 2012 projected plant additions that are included in the revenue requirement in compliance with Section 16-108.5(b)(2) of EIMA. Staff suggests that this amount in the final order will increase transparency in the ratemaking process. AIC asserts that the amount of the "incremental" projected plant additions for 2012 that was included in the proposed revenue requirement was clearly identified in its direct testimony. AIC says for its next formula rate filing to be filed before May 1, 2013, AIC intends to disclose the actual incremental investments for 2012 and the projected plant additions for 2013.

In addition, AIC says the $21.9 million in incremental plant additions included in the revenue requirement does not represent all of the forecasted EIMA incremental expenditures. According to AIC, the 2012 projected plant additions in the revenue requirement for this proceeding represented only the forecasted incremental plant additions that were expected to be in service by the end of 2012. AIC says its infrastructure investment program identified an estimated amount of $24.4 million of incremental capital investment for 2012.

Staff also requested AIC summarize the 2012 projected plant additions by subcategories listed in Ms. Everson's rebuttal testimony. For purposes of formula rate filings, AIC takes no issue with identifying incremental actual and projected plant additions by investment subcategory. AIC claims, however, that for purposes of annual reports required under Section 16-108.5(b), AIC still intends to report incremental annual capital expenditures in the aggregate. AIC also notes that the statute says "including, but not limited to" when providing examples of the investment categories. AIC claims not all actual and projected incremental investments for any given year may readily fit into the categories listed by Ms. Everson.

The Commission has reviewed the Staff proposal and AIC's response, and believes that it would be most useful for AIC to identify the actual 2012 incremental plant additions (which would presumably be consistent with those investments included in AIC's first reconciliation proceeding) in its next formula rate update filing. To the extent possible, AIC should use the subcategories identified in Ms. Everson's rebuttal testimony in this proceeding. The Commission, however, will not prohibit AIC from identifying additional subcategories to the extent necessary.

XII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) AIC is an Illinois corporation engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and is a public utility as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; the Appendix attached hereto provides supporting calculations for the rates approved herein;

(4) AIC's proposed update to its Rate MAP-P should be approved, subject to the conclusions contained herein;

(5) the rates herein found to be consistent with Public Acts 97-0616 and 97-0646 are based on AIC's FERC Form 1 for 2011;

(6) for purposes of this proceeding, the net original cost rate base for AIC's electric delivery service operations is $1,973,634,000;

(7) the rate of return which AIC should be allowed to earn on its net original cost rate base is 8.66%; this rate of return incorporates a return on common equity of 9.71%, on long-term debt of 7.49%, on short term debt of 0.00%, and on preferred stock of 4.98%;

(8) the rate of return set forth in Finding (7) results in base rate electric delivery service operating revenues of $805,540,000 and net annual operating income of $170,917,000;

(9) AIC's electric delivery service rates which are presently in effect are inappropriate and generate operating income in excess of the amount necessary to permit the company the opportunity to earn a fair and reasonable return on net original cost rate base consistent with Public Acts 97-0616 and 97-0646; these rates should be permanently canceled and annulled;

(10) the specific rates proposed by AIC in its initial filing do not reflect various determinations made in this Order regarding revenue requirement;

(11) AIC should be authorized to place into effect amended Rate MAP-P, consistent with the findings of this Order;

(12) AIC should be authorized to place into effect the Rate MAP-P tariff informational sheets designed to produce annual base rate electric delivery service revenues of$805,540,000, which represents a decrease of $43,019,000 or 5.07%; such revenues, in addition to other tariffed revenues, will provide AIC with an opportunity to earn the rate of return set forth in Finding (7) above; based on the record in this proceeding, this return is consistent with Public Acts 97-0616 and 97-0646;

(13) determinations regarding cost of service, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding and consistent with Public Acts 97-0616 and 97-0646; the tariffs filed by AIC should incorporate the rates and terms set forth and referred to herein;

(14) the new charges authorized by this Order shall take effect beginning on the first billing day of the January billing period following the date of the final order in this proceeding; the tariff sheets with the new charges,

however, shall be filed no later than December 18, 2012, with the tariff sheets to be corrected thereafter if necessary;

(15) the Commission, based on AIC's proposed original cost of plant in service as of December 31, 2011, before adjustments, of $5,023,011,000, and reflecting the Commission's determination adjusting that figure, unconditionally approves $5,023,011,000 as the composite original cost of jurisdictional distribution services plant in service as of December 31, 2011; and

(16) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue and presently in effect for electric delivery service rendered by Ameren Illinois Company d/b/a Ameren Illinois are hereby permanently canceled and annulled effective at such time as the new electric delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that Ameren Illinois Company d/b/a Ameren Illinois is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (11) and (12) of this Order, applicable to electric delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that Ameren Illinois Company shall update its formula rate in accordance with this Order.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 5th day of December, 2012.

(SIGNED) DOUGLAS P. SCOTT

Chairman

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company	**:**	
d/b/a Ameren Illinois	**:**	
	:	**11-0282**
Proposed general increase in natural	**:**	
gas rates.	**:**	
(tariffs filed February 18, 2011)	**:**	

ORDER

DATED: January 10, 2012

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ORDER

By the Commission:

I. PROCEDURAL BACKGROUND

On February 18, 2011, Ameren Illinois Company d/b/a Ameren Illinois ("AIC") filed with the Illinois Commerce Commission ("Commission") new and/or revised tariff sheets for electric and gas service. AIC is a combination electric and gas public utility providing residential, commercial, and industrial electric and gas service throughout central and southern Illinois. AIC was formed on October 1, 2010 when Central Illinois Light Company d/b/a AmerenCILCO ("AmerenCILCO") and Illinois Power Company d/b/a AmerenIP ("AmerenIP") merged into Central Illinois Public Service Company d/b/a AmerenCIPS ("AmerenCIPS"). Concurrent with the merger, the newly formed company changed its name to "Ameren Illinois Company." AIC is a wholly owned subsidiary of Ameren Corporation ("Ameren"). The new and revised tariff sheets ("Proposed Tariffs") proposed changes in electric and gas rates and terms of service, to be effective April 4, 2011. On March 23, 2011, the Commission entered two Suspension Orders, one pertaining to the proposed electric tariffs and the other pertaining to the proposed gas tariffs. The Suspension Orders suspended the Proposed Tariffs to and including July 17, 2011 in accordance with Section 9-201(b) of the Public Utilities Act ("Act"), 220 ILCS 5/1-101 et seq. The Suspension Orders identify the specific tariff sheets filed by AIC. Upon suspension, AIC's electric filing became identified as Docket No. 11-0279 and its gas filing became identified as Docket No. 11-0282. On July 7, 2011, the Commission entered Resuspension Orders renewing the suspension of the Proposed Tariffs to and including January 17, 2012.

AIC posted a notice of the filing of the proposed rate increases in each of its business offices and published a notice twice in newspapers of general circulation within each of its service areas, in accordance with the requirements of Section 9-201(a) of the Act, and the provisions of 83 Ill. Adm. Code 255, "Notice Requirements for Change in Rates for Cooling, Electric, Gas, Heating, Telecommunications, Sewer or Water Services." In addition, AIC sent notice of the filing to its customers in bill inserts.

On February 23, 2011, the Administrative Law Judges sent AIC initial lists of deficiencies in its filings in accordance with 83 Ill. Adm. Code 285, "Standard Information Requirements for Public Utilities and Telecommunications Carriers in Filing for an Increase in Rates" ("Part 285"). These first deficiency letters concerned AIC's failure to submit separate cost of service studies ("COSS") and associated schedules for each type of service for each of the three legacy utilities. On March 23, 2011, the Administrative Law Judges sent AIC a second pair of deficiency letters requiring it to submit various other missing information and provide explanations of certain portions of the rate filings. AIC responded to the first deficiency letters on March 24, 2011, when it submitted COSS information for Rate Zone 1 (which corresponds with the former AmerenCIPS), Rate Zone 2 (AmerenCILCO), and Rate 3 (AmerenIP). AIC provided information in response to the second pair of deficiency letters on April 21, 2011.

Petitions seeking leave to intervene were filed by the People of the State of Illinois through the Attorney General (“AG”), Citizens Utility Board (“CUB”), Kroger Company ("Kroger"), Grain and Feed Association of Illinois ("GFA"), AARP, Illinois Competitive Energy Association ("ICEA"), and System Council U-05 of the International Brotherhood of Electrical Workers, AFL-CIO, an association consisting of Local Unions 51, 309, 649, and 702 ("IBEW"). Interstate Gas Supply of Illinois, Inc. and Dominion Retail, Inc. petitioned to intervene separately but participated jointly as the Retail Gas Suppliers ("RGS"). Air Products and Chemicals Company, Archer-Daniels-Midland Company, Cargill, Inc., Caterpillar, Inc., Conoco Phillips Company, Enbridge Energy, LLP, GBC Metals, LLC, Granite City Works, Illinois Cement Company, Marathon Petroleum Company, LP, Olin Corporation, Tate and Lyle Ingredients Americas, Inc., United States Steel Corporation, Viscofan USA, Inc. and Washington Mills Hennepin, Inc. also intervened as members of the Illinois Industrial Energy Consumers (“IIEC”). Best Buy Co., Inc., J.C. Penney Corporation, Inc., Macy’s, Inc., Sam’s West, Inc., and Wal-Mart Stores, Inc. petitioned to intervene as the Commercial Group. All of the petitions to intervene were granted. Commission Staff ("Staff") participated as well.

On August 30, 2011, the Commission hosted a sparsely attended public forum in Springfield for the purpose of receiving public comment on the general increase in electric and gas rates proposed by AIC. Only one public forum was held at the Commission's Springfield office for budgetary reasons. A transcript of the public forum is available on the Commission's e-Docket system.

The Administrative Law Judges consolidated Docket Nos. 11-0279 and 11-0282 on April 8, 2011. Pursuant to due notice, status hearings were held in this matter before duly authorized Administrative Law Judges of the Commission at its offices in Springfield, Illinois on April 18 and September 7, 2011. Thereafter, evidentiary hearings were held September 12 through September 16, 2011. Appearances were entered by counsel on behalf of AIC, Staff, the AG, the Commercial Group, CUB, AARP, GFA, IIEC, Kroger, and RGS.

At the evidentiary hearings, AIC called 19 witnesses to testify. The 19 witnesses include (1) Karen Althoff, AIC's Supervisor of Rates and Analysis, (2) Krista Bauer, Manager of Compensation and Talent Acquisition for Ameren Services Company ("AMS"),[1] (3) Timothy Eggers, a Managing Executive of Gas Supply for AIC, (4) Michael Getz, AIC's Controller, (5) David Heintz, a Vice President of the consulting firm Concentric Energy Advisors, Inc. ("Concentric"), (6) Robert Hevert, President of Concentric, (7) Leonard Jones, AIC's Manager of Rates and Analysis, (8) Randall Lynn, a consultant with the consulting firm Towers Perrin, (9) Ryan Martin, Assistant Treasurer and Manager of Corporate Finance for AMS, (10) James Mazurek, a Partner in Accenture LLP's Management Consulting practice area, (11) Brenda Menke, Income Tax Manager for AMS, (12) Craig Nelson, AIC's Senior Vice President of Regulatory Affairs and Financial Services, (13) Stan Ogden, AIC's Vice President of Customer Service and Public Relations, (14) Ronald Pate, AIC's Vice President of Operations, (15) Gary Rygh, a Managing Director at Barclays Capital, Inc., (16) Ryan Schonhoff, a Regulatory Consultant within AIC, (17) Vonda Seckler, a Managing Executive of Gas Supply for AIC, (18) Ronald Stafford, AIC's Manager of Regulatory Accounting, and (19) James Warren, a tax attorney with the law firm of Winston & Strawn LLP.

Nineteen witnesses testified on behalf of Staff. The Staff witnesses include (1) Scott Struck, a Supervisor in the Accounting Department of the Financial Analysis Division of the Commission's Bureau of Public Utilities, (2) Mary Everson, (3) Dianna Hathhorn, (4) Burma Jones, (5) Bonita Pearce, and (6) Scott Tolsdorf, Accountants in the Accounting Department, (7) Janis Freetly and (8) Rochelle Phipps, Senior Financial Analysts in the Finance Department of the Financial Analysis Division, (9) Peter Lazare, a Senior Rate Analyst in the Rates Department of the Financial Analysis Division, (10) Philip Rukosuev, a Rate Analyst in the Rates Department, (11) Roy Buxton, Manager of the Engineering Department of the Energy Division of the Bureau of Public Utilities, (12) Greg Rockrohr, a Senior Electrical Engineer in the Engineering Department, (13) Yassir Rashid, an Electrical Engineer in the Engineering Department, (14) Eric Lounsberry, Supervisor of the Gas Section in the Engineering Department, (15) Mark Maple, a Senior Gas Engineer in the Engineering Department, (16) David Rearden, a Senior Economic Analyst in the Policy Department of the Energy Division, (17) David Brightwell and (18) David Sackett, Economic Analysts in the Policy Department, and (19) Torsten Clausen, Director of the Office of Retail Market Development ("ORMD").

IIEC offered three witnesses at the evidentiary hearings. IIEC's witnesses include Michael Gorman, Robert Stephens, and David Stowe from the consulting firm Brubaker & Associates, Inc. David Effron, a consultant specializing in utility regulation, Scott Rubin, a consultant and attorney specializing in public utility regulation, and Christopher Thomas, CUB's Director of Policy, testified on behalf of the AG and CUB. James Crist, President of Lumen Group, Inc., a consulting firm focused on regulatory and market issues, offered testimony on behalf of RGS. Kroger called Kevin Higgins, a principal at the consulting firm Energy Strategies, LLC, to testify. Jeffrey Adkisson, GFA Executive Vice President and Treasurer, testified for GFA. The Commercial Group called Steve Chriss, Senior Manager of Energy Regulatory Analysis for Wal-Mart Stores, Inc., to testify.

[1] AMS is the service company subsidiary of Ameren and provides various services to its affiliates, including AIC.

AIC, Staff, IIEC, RGS, the Commercial Group, Kroger, and GFA each filed an Initial Brief and Reply Brief. The AG, CUB, and AARP jointly filed an Initial Brief and Reply Brief. The AG, CUB, and AARP are collectively identified as the Government and Consumer Intervenors ("GCI"). CUB also independently filed a separate Initial Brief on the issue of implementing a retail gas choice program in the AIC service area. IBEW filed an Initial Brief, but no Reply Brief. ICEA filed an Initial Brief and a statement indicating that it joined in the Reply Brief of RGS.

A Proposed Order was served on the parties on November 15, 2011. AIC, Staff, IIEC, and RGS each filed a Brief on Exceptions and Brief in Reply to Exceptions. The AG, CUB, and AARP jointly filed a Brief on Exceptions while only the AG and CUB joined together to file a Brief in Reply to Exceptions. CUB also independently filed a Brief on Exceptions and Brief in Reply to Exceptions on the issue of implementing a retail gas choice program. IBEW filed a Brief on Exceptions as well. GFA, Kroger, and the Commercial Group each filed a Brief in Reply to Exceptions. ICEA submitted a filing indicating that it joined in and adopted RGS' Brief in Reply to Exceptions. The Briefs on Exceptions and Briefs in Reply to Exceptions have been considered in the preparation of this Order.

On December 30, 2011, the Governor signed into law Public Act ("P.A.") 97-0646, which modifies and amends certain provisions of P.A. 97-0616. Among the statutory revisions made by the Public Acts is the addition of a new Section 16-108.5 to the Act. Subsection (c) of Section 16-108.5 provides that a participating utility may elect to recover its electric delivery services costs through a formula rate tariff. As amended by P.A. 97-0646, Section 16-108.5(c) provides that in the event a participating utility filed electric delivery service tariffs with the Commission pursuant to Section 9-201 of the Act that are related to the recovery of its electric delivery services costs, and such tariffs are still pending on the effective date of P.A. 97-0646, the participating utility shall, at the time it files its performance-based formula rate tariff with the Commission, also file a notice of withdrawal with the Commission to withdraw such previously-filed tariffs. Upon receipt of such notice, the Commission is required to dismiss with prejudice any docket that had been initiated to investigate the electric delivery service tariffs, and such tariffs and the record related thereto shall not be the subject of any further hearing, investigation, or proceeding of any kind related to rates for electric delivery services.

On January 3, 2012, AIC filed with the Commission, pursuant to Section 16-108.5(c), proposed tariffs for the recovery of electric delivery service costs through a formula rate tariff. Concurrent with this filing, AIC filed a notice of withdrawal in Docket No. 11-0279, withdrawing the electric delivery services tariffs previously filed in that docket pursuant to Section 9-201 of the Act. On January 4, 2012, the Administrative Law Judges issued a ruling severing Docket Nos. 11-0279 and 11-0282. On January 5, 2012, the Commission entered an Order in Docket No. 11-0279 dismissing the proceeding with prejudice as required by Section 16-108.5(c).

II. NATURE OF AIC'S OPERATIONS

Ameren formed in 1997 with the merger of Union Electric Company and Central Illinois Public Service Company ("CIPS"). Thereafter, Ameren acquired Central Illinois Light Company ("CILCO") in 2002 and Illinois Power Company ("IP") in 2004. The service area of AIC covers roughly the lower two-thirds of Illinois. AIC currently serves approximately 1.2 million electric customers and 840,000 natural gas customers. All of AIC's operations are within Illinois, although an affiliate of AIC (Ameren Missouri Company ("AMC") f/k/a Union Electric Company d/b/a AmerenUE) provides utility service in Missouri. At one time, AMC's AIC's predecessor company served the St. Louis Metro East area in Illinois. That area has since been subsumed within the service area of Rate Zone 1. Other affiliates of AIC provide unregulated services.

III. AIC'S PROPOSED TEST YEAR AND REVENUES

AIC proposes to use a future test year consisting of the 12 months ending December 31, 2012. No party objects to the use of this test year. The Commission concludes that the future test year AIC proposes is acceptable for purposes of this proceeding.

The Proposed Tariffs reflect a total increase in delivery service revenues of approximately $50.7 million for all AIC natural gas customers. AIC presented its original proposed natural gas revenue changes based on the combination of the three Rate Zones. AIC's original proposed change in the delivery service operating revenue is as follows:[2]

	Revenue Change	% Change
Combined Rate Zones as reflected in Proposed Tariffs	$50,694,000	16.9

AIC determined the originally requested revenue using a return on equity for natural gas operations of 11.00%.

Over the course of this proceeding, however, AIC lowered its total requested gas delivery service revenue increase to approximately $49.6 million. In response to deficiencies identified by the Administrative Law Judges, AIC also provided its proposed revenue changes by each Rate Zone. The pending proposed changes in the delivery service operating revenues for each Rate Zone are as follows:

[2] The numbers contained in the table reflect only proposed delivery service revenues since it is only those revenues at issue in this proceeding.

	Revenue Change	% Change
Rate Zone 1	$10,690,000	15.4
Rate Zone 2	$14,632,000	21.6
Rate Zone 3	$24,207,000	15.3

AIC determined the revised requested revenues using a return on equity for natural gas operations of 10.75%.

AIC's most recent electric and natural gas delivery service rate cases considered by the Commission were consolidated Docket Nos. 09-0306 through 09-0311 (Cons.). The Commission entered the Order in that matter on April 29, 2010. Shortly thereafter the Commission corrected calculation errors and entered on May 6, 2010 a Corrected Order authorizing a total aggregate revenue increase for AIC of approximately $14,727,000; substantially less than the approximately $130,000,000 that AIC sought at the close of the December 2009 evidentiary hearing in that proceeding. On November 4, 2010, the Commission entered an Order on Rehearing authorizing an additional $29,162,000, for a final total aggregate revenue increase of $43,889,000.

IV. RATE BASE

A. Resolved Issues

During the course of this proceeding, witnesses recommended various adjustments to AIC's rate base. But upon receiving additional information from AIC, those recommending adjustments sometimes withdrew their suggestions and indicated that they accepted AIC's explanation. For purposes of judicial economy, the Commission does not discuss here instances where a dispute is resolved without any adjustment to the rate base AIC proposed in its direct testimony. Such issues may be found in the parties' briefs. Where the resolution of a dispute or correction of an error, however, resulted in an adjustment to rate base, a list of such adjustments follows.

1. Federal Income Tax ADIT Correction

Staff witness Hathhorn proposes adjustments to decrease AIC’s gas federal accumulated deferred income tax ("ADIT") amounts, thereby increasing rate base, to correct the error of unreasonable amounts identified in Ameren Ex. 16.2, Schedule 1. AIC explains 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. AIC accepts Staff's adjustments and includes them in its rebuttal revenue requirements. The Commission finds the correction of this error appropriate and adopts it.

2. State Income Tax ADIT - Bonus Depreciation

Staff witness Hathhorn proposes adjustments to increase AIC's gas state ADIT amounts, thereby decreasing rate base, because AIC's proposed amounts did not reflect the effect of federal bonus depreciation on the state ADIT liability and were therefore unreasonable. AIC's position was based on Illinois' past practice of decoupling from federal tax provisions for bonus depreciation. AIC states in discovery, however, that the State of Illinois has not passed legislation to follow its past treatment of decoupling from the federal tax provisions of bonus depreciation. AIC accepts Staff's adjustments and includes them in its rebuttal revenue requirements. AIC further states that the AG/CUB proposed adjustment for ADIT-Bonus Depreciation is very similar to Staff's adjustment that it accepts. The Commission finds that the two adjustments proposed by Staff and the AG/CUB are nearly the same and will adopt Staff's adjustment.

3. ADIT - Manufactured Gas

AG/CUB propose an adjustment to AIC's gas rate base to eliminate the deferred tax debit balance related to "Manufactured Gas & Other Environmental Cleanup" in the total balance of ADIT. AIC accepts the adjustments proposed by AG/CUB for amortization of Investment Tax Credits and for ADIT-MGP. The Commission finds the adjustment reasonable and adopts it.

4. Budget Payment Plans

Staff witness Tolsdorf proposes an adjustment to reduce rate base by the average over-collection associated with the budget payment plan. According to AIC's calculations, it has over-collected from customers on average from 2007 through 2010. Based on its own forecasts, AIC will over-collect from its customers during the test year as well. This over-collection represents a rate-payer funded source of capital and, as such, should be a reduction to rate base. AIC accepts Staff's adjustment in its rebuttal testimony. The Commission finds the adjustment reasonable and adopts it.

5. Gas in Storage

Staff witness Maple proposes an adjustment to the amount of working capital for gas in storage to reflect current market prices. AIC's originally projected working capital allowance for gas in storage for the test year was based on pricing information from June 2010. AIC provided updates to its requested working capital allowance for gas in storage based on more recent May 2011 pricing data for the test year. Staff's adjustment related to gas pricing is based on May 2011 pricing information as well. On rebuttal, Staff also agreed to use AIC's original proposed volumes of gas in storage as stated in AIC's Schedule F-9. The Commission finds the adjustment reasonable and adopts it.

6. Merger Costs

Staff witness Pearce proposed to reduce merger costs to remove the capital costs of the merger as identified in the Merger Integration and Process Optimization ("MIPO") study from the test year revenue requirement. On rebuttal, AIC made a reduction to labor costs to correct for double counting of the amount of labor capitalized. AIC then adjusted the amount of capital investment related to the merger included in test year rate base related revenue requirements. Following these corrections, Ms. Pearce withdrew her adjustment to merger costs. The Commission finds the correction of the error appropriate and adopts it.

7. Previously Disallowed Incentive Compensation

Staff proposes to reduce rate base for capitalized incentive compensation amounts that had been previously disallowed by the Commission, as detailed on Staff Ex. 3.0, Schedule 3.05. AIC accepts Staff's adjustment in rebuttal testimony. The Commission finds the adjustments reasonable and adopts them.

B. Contested Issues

1. Capital Additions Adjustment

a. Staff Position

Staff witness Rashid recommends that the Commission disallow $1,833,738 from AIC's proposed rate base, which is the cost of 3 capital projects that support gas delivery service that AIC 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 Sections 9-211 and 9-212 of the Act. Section 9-211 provides in full:

> 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.

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.

In response to Staff's proposed adjustment, AIC introduced Ameren Ex. 26.1, which included a list of 16 projects, the costs for 3 of which AIC initially included in its proposed gas rate base, but later decided to defer or cancel. The combined cost of these 3 projects included in its proposed gas rate base is $1,833,738. Ameren Ex. 26.1 also includes a list of 13 projects that AIC labeled as "projects not included in rate base added in 2011-2012." Of these 13 projects, 4 projects will support gas delivery service. The combined cost for these 4 projects is $5,719,364. Staff understands that AIC 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. Although AIC did not propose adjustments to include these 4 projects in its rate base, AIC argues that the Commission should allow it to use the money it originally allotted to implement the delayed and cancelled projects for the implementation of the new projects that it identified in response to Mr. Rashid's discovery of those delayed and cancelled projects. Staff insists that the Commission should not allow AIC to make these substitutions. According to Staff, it is AIC's responsibility to provide the Commission with an accurate forecast of test year capital projects expense that may be reviewed to determine whether they are prudent and used and useful. Because AIC's forecast for test year capital additions was not accurate, Staff urges the Commission to disallow $1,833,738 from AIC's proposed rate base.

Contrary to AIC's argument (See AIC Initial Brief at 14-15), Staff states that the used and useful inquiry does not raise an implication that utilities must provide a list of every capital addition planned for a future test year. Part 285 does not require a utility to list every single capital project it plans to implement between the rate case filing and the end of a future test year. Staff notes, however, that this does not preclude an investigation of the projects, included in the forecast, beyond those required to be disclosed under Part 285 if, during discovery, Staff determines that it is necessary. In this proceeding, Staff reviewed projects not included in AIC's Schedule F-4.

Staff disagrees with AIC's suggestion that the deferment or cancellation of certain projects should not affect rate base if a utility identifies additional projects of equal or greater cost that it states it will complete within a future test year. Staff maintains that the proper focus is not the overall forecast. Moreover, Staff finds misplaced AIC's reliance on Schedules G-1 and G-8 as the basis for the Commission to consider the new projects as part of its overall forecast. Schedule G-1 compares forecast period data to actual data to demonstrate the reliability and accuracy of the utility's forecast for each of the prior three years. Schedule G-8 provides a comparison by plant function of the original budget of capital additions and retirements to actual capital additions and retirements for each of the most recent three years. Although the purpose of these schedules is to provide some historical context for the forecast, Staff insists that they do not provide support for allowing new projects to be substituted for the projects relied upon in the forecast. Staff avers that Schedules G-1 and G-8 do not compare the difference between capital projects that AIC wholly eliminated and a set of new projects that it intends to replace them with, but rather it presents a comparison between what the utility has budgeted in the past and the extent to which it has followed that budget. Staff insists that historical Schedules G-1 and G-8 are not relevant to and do not support using new projects to support the capital additions forecast. If AIC's position is adopted, Staff observes that in rate cases with future test years, a utility could provide its forecast for capital additions with an overall capital spending level, which would remove the statutorily required "used and useful" analysis from the capital additions component of rate base.

Staff maintains that it is important that the Commission adopt its recommendation, not just for this AIC proceeding, but for all future rate cases where utilities decide to use a future test year. If the Commission accepts AIC's last minute substitution of new, previously unidentified capital projects in place of the projects identified in the forecast, Staff fears that any used and useful analysis will become irrelevant. Staff states further that adoption of the "overall level of forecasted plant additions" would enable utilities with future test years to make whatever substitutions necessary to justify the level of their forecasted rate base additions in response to Staff's proposed adjustments. Staff fears that the Commission would then lose its ability to hold the utilities to any meaningful rate base forecasting standards.

b. AIC Position

In response to Staff's proposed adjustment, AIC argues that Staff's adjustment exhibits a fundamental misunderstanding of ratemaking in a future test year. AIC states that a future test year, by definition, requires an evaluation of forecasted plant additions scheduled to be placed in service in the future. In any given year (whether a rate case is pending or not), AIC relates that projects budgeted for that year may not be completed. On the other hand, AIC continues, projects that were not budgeted may also need to be completed. Thus, in a future test year, AIC contends that the plant in service component of rate base is determined by examining the overall level of forecasted plant additions. AIC maintains that this is done not by looking at individual projects, but by examining the accuracy and reliability of the utility's rate case forecast, measured in large part by looking at historical budget-to-actual information.

AIC contends that there are two problems with Staff's argument that any project not completed during the test year does not meet the "used and useful" standard and therefore cannot be recovered in rates. First, AIC argues that Staff does not observe the standard it claims AIC should be held to. Noting Mr. Rashid's claim that it is AIC's duty to provide an accurate forecast of test year capital projects expense that may be reviewed to determine whether they are prudent and used and useful, AIC asserts that this implies that utilities must provide a list of every capital addition planned for a future test year, with a corresponding duty on Staff to review this list and determine whether each project is or will be prudent and used and useful. But, AIC observes, Mr. Rashid agrees that the rules for future test years do not require utilities to list every single capital project they plan between the rate filing and the end of the test year. To the contrary, the instructions for Schedule F-4 require utilities to provide information only for certain major capital projects above a certain dollar threshold. (See Part 285.6100) If, as AIC understands Mr. Rashid to be saying, Staff has a duty to review all capital additions to ensure that they will be used and useful during the test year, AIC points out that that duty was not observed here. The second problem that AIC raises with regard to Staff's position is that Staff ignores the overall capital additions forecast by AIC and the reliability of that forecast. In future test year cases, AIC asserts that determining the appropriate level of capital additions to be included in rate base must necessarily focus on the utility's forecast. AIC argues that the overall level of forecasted capital expenditures is what counts, not whether individual projects are or are not completed during the test year.

AIC also takes issue with the distinction that Staff draws between actual operations and the review conducted in a rate case. AIC understands Staff to argue that a utility should not be allowed to respond to adjustments to its capital projects expense by expanding its list of test year capital projects. According to AIC, this is another way of suggesting that once a utility locks down its forecast and files a rate case using a future test year, the ratemaking process should suspend disbelief and assume every capital addition will be placed in service precisely as scheduled and exactly on budget. AIC asserts that this is not how the real world works.

AIC avers that forecasting which capital additions will be placed in service in the future is an exercise of judgment, not clairvoyance. AIC states that operating the system safely, reliably, and efficiently requires it to constantly review planned capital projects and re-prioritize when necessary. The fact that it must re-prioritize projects, AIC continues, does not establish that the level of overall capital additions forecasted for the test year is unreasonable or inaccurate. Furthermore, AIC contends that the Commission's rules recognize that setting rates in a future test year requires a focus on the overall level of planned capital expenditures, not individual projects. Thus, AIC states that the plant in service component of its rate base is not based on when individual projects are expected to be placed into service. Plant in service is presented as a simple average of December 31, 2011 and December 31, 2012 plant balances. The plant additions and retirements forecasted during this period are based on the AIC board-approved 2012 budget. AIC states that the G Schedules submitted in this case provide information that can be used to evaluate the reasonableness and accuracy of AIC's budget. Schedules G-1 and G-8, for example, require comparative data of budgeted versus actual capital expenditures and plant additions for the most recent three years. During the 2007-2009 period, AIC reports that overall gas capital expenditures were 102% of budget. AIC adds that gas gross plant additions were 2% over budget. AIC states that this information shows that it typically spends more on capital projects than it has budgeted. AIC also states that Staff does not dispute that AIC's overall forecasted plant additions are consistent with historical trends, or that AIC historically spends more on capital projects than it has budgeted.

Additionally, and contrary to recognizing any distinction between "rate cases" and "operations," AIC relates that Section 285.7015 of Part 285 specifically requires an explanation of whether the forecast for the test year uses the same assumptions and methodologies as forecasts prepared for management and other entities, such as the Securities and Exchange Commission ("SEC") and ratings agencies. Section 285.7020 requires a statement that the accounting treatment for anticipated events in the test year forecast is the same treatment that will be applied once the event has occurred. Not only is consideration of capital expenditures within a rate case not distinct from operations; AIC contends that the latter dictates the former. AIC urges the Commission to reject Staff's distinction between "rate cases" and "operations."

AIC also argues that Staff's "cost shifting" characterization is misguided. AIC indicates that the new projects listed in Ameren Ex. 26.1 were provided simply to illustrate that "shifting dollars" has no significant or material effect on the overall level of capital additions that should be included in rate base. AIC is not requesting recovery of the increase in capital expenditures. Moreover, AIC does not believe that Staff appreciates that under Section 287.30 of 83 Ill. Adm. Code 287, "Rate Case Test Year" ("Part 287"), a utility's ability to update schedules and workpapers for a future test year is limited. If an update is even allowed, only one update may be filed, and only then according to a schedule established by the Administrative Law Judge. In this proceeding, AIC was afforded the opportunity to file an update with its rebuttal testimony. AIC did not do so because it did not identify any changes to the forecast "significantly and materially" affecting the revenue requirement, which is a condition for filing an update under Part 287.30(b)(1). If it had filed an update based on the changes in capital projects, AIC states that rate base would increase by approximately $3.9 million, as opposed to the $1.8 million decrease proposed by Staff. If the Commission is going to entertain an adjustment based on routine changes in project priorities, AIC insists that basic fairness and symmetry dictate that the adjustment include both deferred projects and additional projects. For the reasons discussed above, however, AIC contends that no such adjustment is necessary or appropriate.

c. IBEW Position

IBEW supports AIC's overall test year level of capital additions. IBEW agrees with AIC witness Nelson that the overall level of forecasted capital additions should be considered when evaluating rate base, not individual projects. IBEW also agrees with AIC that netting the cancelled projects and the new projects confirms that the overall level of capital additions forecasted for the test year is reasonable, reliable, and accurate. Moreover, IBEW observes that the few individual projects being cancelled or deferred and the addition of other projects has no material effect on forecasted capital additions.

IBEW also observes that AIC initially reduced its 2010 capital budget in June 2009 and further reduced its operating and capital budgets following the Commission's Order in AIC's last rate case. IBEW understands that many of these spending cuts were carried forward into the 2011 operating budget. But under such cuts, IBEW questions whether AIC can continue to provide adequate, safe, and reliable service. IBEW states that each project identified by AIC requires cost recovery so that it can continue to provide adequate, safe, and reliable service. Furthermore, to complete the projects, IBEW relates that AIC plans to hire the additional personnel that will be needed to perform the test year electric and gas projects.

d. Commission Conclusion

In any large organization, projects planned for completion even a few years into the future may not be completed while other projects not anticipated may be implemented. The Commission recognizes that regulated utilities are subject to this reality and respects their need to react to changing plant needs. At the same time, the Commission must also abide by the Act to ensure that a utility's investments are prudently incurred and that plant in rate base is used and useful. Schedule F-4 assists the Commission in ensuring that only the costs for proper capital additions are included in rate base. Because trying to review all capital additions in the limited span of a rate case is not practical, Schedule F-4 calls for details on the most expensive projects. Staff and other parties are also free to inquire about other capital additions as well.

In this instance, Staff recommends disallowing approximately $1.8 million because by AIC's own admission, the associated projects will not be completed by the end of the 2012 test year. Rather than accept the adjustment, AIC offers in rebuttal testimony additional plant additions not included in the test year rate base with total costs exceeding that which Staff seeks to disallow. When one considers Staff's recommended disallowance with its newly planned capital additions, AIC contends that the overall forecasted budget is still essentially the same.

The problem with AIC's position, however, is that the Act is not concerned with the overall plant investment of a utility. The Act is concerned with the prudency and used and usefulness of particular utility assets. The Commission has consistently applied this statutory requirement in the past. While AIC may find itself needing to add distribution plant that it did not anticipate when preparing its rate case, it chose not to update its future test year and should not be allowed to circumvent the process for reviewing its plant additions by focusing on its overall capital expenses.

Furthermore, the Commission shares Staff's concern that if it accepts AIC’s substitution of new, previously unidentified capital projects in place of projects disallowed from the future test year, the prudency and used and useful analyses will become irrelevant. Adoption of the "overall level of forecasted plant additions" standard would enable utilities with future test years to make whatever substitutions necessary to justify the level of their forecasted rate base additions in response to other party’s proposed adjustments. The Commission would then lose its ability to hold the utilities to any meaningful rate base forecasting standards. Accordingly, Mr. Rashid's adjustment on this issue is accepted.

2. Cash Working Capital

There is a single issue with respect to the cash working capital (“CWC”) methodology, relating to the lag days associated with Energy Assistance Charges (“EAC”) that AIC collects from its customers and remits to the State of Illinois. AIC and Staff agree that the EAC funds are, on average, available to AIC on the 16th day of each month. AIC remits the EAC funds as of the 20th day of each month, and thus calculates that the funds are available to AIC for four days. Staff notes that the enabling legislation requires funds to be remitted by the 20th day of the following month (See 305 ILCS 20/13(f)), and thus calculates that AIC has the use of the funds for up to 35 days.

The question is whether the additional month that AIC could hold the funds should be imputed for CWC purposes. If AIC were to change its practices, it would mean that it would effectively remit no EAC charges to the State for one month. Hence, at the test year level of EAC charges, in the first year of the change, AIC would remit about $2.3 million less to the State than it would under its current practices. AIC states that this could impact the comprehensive low income energy programs administered by the Illinois Department of Commerce and Economic Opportunity with these funds. AIC requests that, in calculating the CWC requirement, the Commission recognize AIC's past method of remitting this pass-through tax and avoid any negative impacts on the State, low-income customers, and AIC. Staff, on the hand, contends that ratepayers should not bear the cost of AIC’s unnecessary early payment and urges the Commission to base the CWC calculation on AIC's access to these funds and not the date AIC chooses to remit them.

The Commission understands Staff's position but is not inclined to adopt it. Given the circumstances surrounding the EAC, the Commission does not believe that the adjustment sought by Staff is warranted. The Commission will revisit this issue, however, if AIC alters its EAC remittance schedule.

3. Accrued OPEB Liability

a. AIC Position

In addition to a pension, AIC provides employees with other post-employment benefits (“OPEB”), which consist of such benefits as health care, life insurance, tuition assistance, and other post retirement benefits outside of a pension plan. AIC's OPEB expense, determined in accordance with Accounting Standards Codification ("ASC") 715-60, formerly Financial Accounting Standard No. 106, represents the accrued cost of providing these benefits. To the extent accruals are greater than cash contributions into the OPEB trust, an unfunded liability will exist. In previous rate cases, including recent AIC rate cases, the Commission has deducted the accrued OPEB liability from rate base. AIC understands that the basis for this adjustment has been that ratepayers have provided AIC with the OPEB dollars to fully fund the liability. It is further assumed that AIC has just not placed those dollars in the OPEB trust, resulting in money available to AIC at zero cost. AIC also understands that a deduction to rate base in the amount of the liability is considered appropriate because ratepayers have provided the utility with a cost-free source of capital and ratepayers should not have to pay a return on costs that they have already funded.

In this proceeding, AIC believes that it can avoid a deduction to rate base because it thinks it can demonstrate that the OPEB liability does not represent ratepayer-supplied funds withheld from the trust. Ameren Ex. 2.4 purports to identify with reasonable certainty the portion of the existing OPEB liability that has been recovered from ratepayers. According AIC's analysis, ratepayers have provided only half of the dollars required to fully fund the existing OPEB liability. AIC claims further to have made cash contributions to the OPEB trust to fund expenses accrued in excess of ratepayer-supplied OPEB funds.

AIC insists that it is not appropriate to deduct the remaining liability from rate base when ratepayers have not funded those dollars. AIC states that it is the ASC 715-60 accruals that it recovers as an annualized expense through rates. AIC indicates that it lacks a mechanism that automatically adjusts OPEB expense in rates to match annual ASC 715-60 accruals. Thus, AIC records an amount of OPEB expense for any given period that will likely, if not always, vary from the amount recovered in rates.

If the utility has not recovered enough OPEB dollars to fully fund the liability, AIC contends that the entire liability cannot represent “cost-free” funds. If, for example, a utility’s ASC 715-60 expense is $4 million, it collects $2 million in rates, and it pays only $1 million into the trust, the utility’s accrued liability may be $3 million, but only $2 million of that liability represents funds from ratepayers. In the past, utilities have argued in the abstract that the fundamental premise for the adjustment is flawed if the utility recovers less OPEB dollars in rates than what it accrues, regardless of the cash placed in the trust. Some portion of the liability in theory must represent dollars not collected, they have argued. AIC notes that the Commission has dismissed such arguments. But AIC maintains that it is inappropriate to believe that the excess liability is solely attributable to the utility.

AIC believes that this is the first case in which any utility has submitted evidence analyzing ratepayer OPEB dollars since implementation of ASC 715-60. In preparing Ameren Ex. 2.4, AIC conducted an analysis of OPEB dollars accrued to expenses, included in AIC rates, and placed in the OPEB trust, since the adoption of ASC 715-60. The purpose was to determine whether ratepayers have fully funded the existing liability. Ameren Ex. 2.4 shows generally that, although ratepayer-supplied funds may have exceeded cash contributions for AmerenCIPS since the adoption of ASC 715-60, for both AmerenCILCO and AmerenIP ratepayer-supplied OPEB funds were inadequate to fully fund the liability. Specifically, AIC reports that as of September 30, 2010, the balance of AIC’s OPEB liability was approximately $120,515,000($35,528,000 allocable to gas operations). But a review of prior rate orders, exhibits, and workpapers since the adoption of ASC 715-60 shows that only $60,253,000 ($17,763,000 allocable to gas operations) of that liability has been recovered in rates. AIC concludes that it is impossible for it to have collected enough OPEB dollars from ratepayers to justify the reduction of the entire amount of the liability from rate base. Furthermore, in preparing its filing, AIC pledged to contribute additional funds to the trust to cover the ratepayer portion and reflected that expected contribution in the latest actuarial forecast. Since the initiation of this proceeding, AIC has fulfilled that pledge and now contends that the entire remaining liability on its books for the test year is the non-ratepayer-supplied portion. AIC states that it is not seeking to recover the accrued OPEB dollars allegedly not recovered in rates. Nor is AIC seeking recovery of, or a return on, dollars placed in the OPEB trust in excess of the ratepayer-supplied portion. AIC states that it is simply asking the Commission not to make a deduction to test year rate base to reflect dollars that it alleges it never received.

AIC suggests that GCI ignores its evidence when they argue for a rate base deduction reflecting OPEB liability. AIC notes that AG/CUB witness Effron does not contend that the liability is ratepayer funded, but instead simply argues that the test year balances of accrued OPEB liabilities should be deducted from rate base, consistent with the Commission's treatment in AIC's prior rate cases. AIC contends that his argument that the Commission should deduct the balance now just because it did so before should be rejected. AIC argues that it is not consistent with the Commission's prior cases to deduct the amount of liability from rate base if AIC has demonstrated that those dollars have never been collected.

AIC rejects Staff's numerous reasons for why an adjustment should still be made. First, AIC denies that the corresponding employee benefits costs reflected in the revenue requirement have been enough to fully fund the existing liability. Second, in response to Staff's claim that it is not possible to disaggregate prior base rates by line item in order to determine how much has been recovered for each element of the revenue requirement, AIC contends that Ameren Ex. 2.4 shows that not to be true. Third, Staff contends that after rates are established, they are presumed adequate to allow a utility 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. Staff points to Mr. Effron's testimony and argues that this liability represents expenses accrued in excess of actual payments; therefore, it is a proper reduction of rate base. But AIC reiterates that the fact that the liability exists or the Commission has deducted the liability from rate base in prior rate cases is not a justification for making the same deduction in this case based on the record evidence AIC presented.

b. Staff Position

Staff urges the Commission to accept its proposed adjustment to reduce rate base for the projected average OPEB liability for the test year ending December 31, 2012. Staff maintains that the OPEB liability represents a cost-free source of capital that was provided by ratepayers. As such, Staff contends that ratepayers should not have to pay a return on it. Staff identifies numerous cases in which the Commission has concluded that OPEB liability should be treated as a reduction of rate base. Staff specifically notes the following rate cases: Peoples Gas Light and Coke Company ("Peoples")/North Shore Gas Company ("North Shore"), Docket Nos. 07-0241 and 07-0242 (Cons.); Peoples/North Shore, Docket Nos. 09-0166 and 09-0167 (Cons.); Northern Illinois Gas Company d/b/a Nicor Gas Company ("Nicor"), Docket No. 04-0779; and the previous rate cases for AIC's legacy utilities, Docket Nos. 06-0070 through 06-0072 (Cons.).

Staff is not persuaded by AIC's analysis depicted in Ameren Ex. 2.4. Staff asserts that 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. Staff contends that AIC's 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. In other words, Staff believes that 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, Staff points out that a utility may request a general increase in rates. Staff also observes that during the time those rates are effective, some expenses likely increase, while others may decline. Therefore, Staff concludes that 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, Staff asserts that it is presumed that recovery was adequate to cover costs until new rates were approved.

Staff also fears that AIC's efforts to revisit past revenue requirements because they were allegedly insufficient 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, Staff states that 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. Staff asserts that the treatment of the OPEB liability sought by AIC runs counter not only to well-established principles of ratemaking, but also to well-established principles of law.

Finally, Staff witness Pearce notes 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 AIC's response to AG-DJE 3.19 Attach, line 4, column (c). As Ms. Pearce explains, this response demonstrates that even after the additional 2011 contribution from AIC, AIC projects an OPEB liability will remain for the 2012 test year. Staff states that this liability represents expenses accrued in excess of actual payments; therefore, it is a proper reduction of rate base.

c. GCI Position

GCI argues that test year balances of accrued OPEB liabilities should be deducted from plant in service in the calculation of AIC’s rate bases in the present cases. GCI agrees with Staff's view that ratepayers have supplied funds for future obligations; therefore, a source of cost-free capital has been provided to the utility, which should be recognized in the revenue requirement as a reduction from rate base. GCI asserts that the OPEB issue in this case, particularly regarding AIC’s control of ratepayer supplied OPEB funds, is similar to the accrued OPEB issue in other cases, where the Commission has definitively addressed the matter. GCI directs the

Commission's attention to Docket No. 95-0129, Docket Nos. 09-0166 and 09-0167 (Cons.), Docket Nos. 06-0070 et al. (Cons.), and Docket Nos. 07-0585 through 07-0590. (Cons.). GCI states further that AIC has offered no valid reason in this case to explain why the Commission should deviate from prior treatment of OPEB. GCI therefore concludes that the Commission should adopt the adjustments for the accrued liability proposed by AG/CUB witness Effron and supported by Staff. The adjustment to rate base as proposed by AG/CUB witness Effron and Staff witness Pearce reduces AIC's rate base by $6,850,000 and $3,062,000 for electric and gas, respectively. These adjustments to rate base are stated net of ADIT.

d. Commission Conclusion

When the Commission enters an order establishing rates, those rates are presumed adequate to allow a utility an opportunity to recover its costs, including a return on rate base. A utility's OPEB expenses are reflected in those rates. Because ratepayers have provided the utility with "OPEB dollars" through the presumptively adequate rates, it is also presumed that the utility will apply those ratepayer supplied "OPEB dollars" to its OPEB accruals. Historically, if a utility's OPEB fund is deficient, because the approved rates were designed to avoid any OPEB deficiency, the Commission recognizes that the utility's failure to apply collected "OPEB dollars" means that the utility has the use of those dollars as a cost-free source of capital. Because ratepayers should not have to pay a return on costs that they have already funded, the Commission deducts from rate base the amount of the OPEB liability.

AIC now insists that through Ameren Ex. 2.4, it has demonstrated that ratepayers have not paid what they owed toward OPEB expenses. AIC contends that only approximately $60 million ($18 million allocable to gas) of the $120 million liability ($36 million allocable to gas operations) has been recovered in rates. After contributing $100 million toward OPEB expenses during the course of these proceedings, AIC argues that the remaining balance of the liability represents funds not yet collected through rates. AIC wants the Commission to take note of this alleged ratepayer deficiency and decline Staff and GCI's recommendation that nearly $3 million representing OPEB liability be deducted from rate base.

Although the Commission finds AIC's position a novel approach, it does not find it appropriate. AIC professes to somehow have parsed from past Commission-approved rates that amount attributable to OPEB expenses for each of the legacy utilities. Because its current OPEB accruals exceed that which it believes it was entitled to under prior and existing rates, AIC seems to suggest that past and existing rates clearly have not sufficiently collected "OPEB dollars." The Commission questions the validity of such an analysis and wonders how AIC was able to isolate that specific element of the legacy utilities' rates over nearly 20 years for two of the companies and nearly eight years for the third and account for the myriad of variables affecting its revenues and expenses over those years. Moreover, AIC's analysis would seem to amount to single-issue retroactive ratemaking. The Commission finds it wholly inappropriate to attempt to reconcile one component within decades worth of approved rates with what a utility believes that one component should have produced in revenue.

Had AIC found its revenues to be insufficient to meet its obligations and provide reliable and safe gas and electric service, it was within its ability to seek additional revenue through electric delivery services rate filings and natural gas rate filings. The record reflects that AIC in fact availed itself of these opportunities. Moreover, Section 16-111(d) of the Act provided for rate relief during the mandatory transition period if certain hardships existed for AIC. For AIC to now claim that it was unable to address what it now perceives as a past rate deficiency is disingenuous.

In conclusion, the Commission agrees with the arguments of Staff and GCI. Consistent with past practice, AIC's accrued OPEB liability shall be deducted from rate base. AIC's analysis and the improper precedent it would establish are rejected.

4. Accumulated Provision for Injuries and Damages

a. Staff Position

Staff recommends an adjustment to reduce rate base by the amount of Accumulated Provision for Injuries and Damages ("APID") as shown in Staff Ex. 22.0R2, Schedule 22.02. Staff relates that the APID represents previously expensed costs (expense accruals) recovered from ratepayers that have accumulated over time on the balance sheet. These funds, Staff asserts, represent a source of cost free capital for AIC which entitles ratepayers to the benefit of a rate base deduction. The point of contention between Staff and AIC is whether or not the dollars which fund the APID have in fact been recovered from ratepayers. Staff's position is that the injuries and damages ("I&D") expense, regardless of how the amount is determined, is recovered from ratepayers. A portion of that expense funds the APID and the ratepayers are entitled to the benefit of a rate base deduction for these accumulated funds.

AIC argues that ratepayers have not funded the APID because in this and prior rate cases AIC normalized the test year I&D expense using an average of payouts rather than the more volatile and fluctuating expense accruals. Staff states that AIC would have the Commission believe that by normalizing this expense, the ratepayers are no longer paying the I&D expense. According to Staff, what AIC fails to acknowledge is that the normalization adjustment is made to set the appropriate amount to collect from ratepayers for I&D expense. The normalization adjustment more accurately calculates how much will be collected from ratepayers for I&D expense on a recurring basis, but does not eliminate recovery of the expense itself.

Staff notes that AIC witness Stafford calculates the five year average of cash claims paid adjusted for inflation to be $1.87 million and the 2012 reserve accruals to be $3.40 million. If the Commission accepts AIC's argument, Staff continues, it would mean that if one removes from the revenue requirement the expense accruals that fund the APID ($3.40 million) and add in its place the cash claims paid ($1.87 million), then somehow the ratepayers are no longer funding the APID. Staff finds this argument to be without merit and urges its rejection. Staff insists that a portion of the amount collected for I&D expense, regardless of how the amount of that expense is determined, funds the APID. Staff maintains that ratepayers are entitled to a rate base reduction for the amount of these accumulated funds.

Furthermore, Staff contends that application of AIC's argument to the facts demonstrates that ratepayers have funded a balance greater than the APID. Staff reports that Mr. Stafford testifies that the normalization adjustment has occurred in each rate case dating back to Docket Nos. 06-0070 et al. (Cons.). In each of the last two cases, however, Staff notes that the overall adjustment increased the I&D expense rather than decreasing it. Thus, Staff finds that AIC's adjustments have allowed it to recover more, not less, than the expense accruals necessary to fund the APID. This leads Staff to conclude that AIC's argument is erroneous and should be dismissed by the Commission.

b. AIC Position

In AIC's last three rate cases, the Commission has not made a deduction to rate base to reflect the amount of the accumulated reserve for I&D. Staff, however, proposes such a reduction to rate base in this proceeding. AIC reports that the Commission rejected this same adjustment the last time it was proposed in an AIC rate case, Docket Nos. 07-0585 et al. (Cons.). AIC states further that pro forma adjustments have eliminated Account 925 expense accruals and added in its place a normalized level of cash claims. AIC relates that this was the approach recommended by the AG and CUB and adopted by the Commission in Docket Nos. 06-0070 et al. (Cons.). AIC adds that it was the approach subsequently approved by the Commission in Docket Nos. 07-0585 et al. (Cons.) and Docket Nos. 09-0306 et al. (Cons.). In preparing this rate filing, AIC states that it again adjusted test year I&D expense to remove the test year accrual for claims to be paid. The accrual has been replaced with a historical average of actual claims paid for the five year period 2006-2010.

AIC contends that no argument or evidence has been presented in the record to cause the Commission to change its view. AIC explains that the use of a cash claims basis to adjust the amount of I&D expense to recover in rates eliminates the existence of the reserve balance for ratemaking. AIC has been recovering a normalized level of actual cash claims paid. Like other normalized expenses, such as storm costs, AIC states that the level of expense included in rates is based on actual costs incurred by AIC, not on accrued estimates of AIC's future claims expense.

AIC asserts that the distinction between cash and accrual accounting is critical. Under accrual accounting, AIC indicates that a liability for future claims exists for financial reporting. Under cash accounting, however, no liability exists. AIC states that the use of actual cash claims paid rather than expense accruals for ratemaking means that customers are not funding the accrued I&D liability. AIC thus reasons that no liability exists for ratemaking. In other words, AIC contends that if accruals have been eliminated in setting I&D expense, they are not in the revenue requirement and are not being funded by ratepayers. Moreover, AIC states that Staff cannot identify any I&D expense accruals that have been included in rates since Docket Nos. 06-0070 et al. (Cons.). Nor, AIC continues, can Staff reconcile its adjustment with the fact that no adjustment to reduce rate base for the reserve has occurred in AIC's last three rate cases.

Despite the fact that no accruals have been funded by AIC's ratepayers, Staff contends that the normalized level of cash claims paid is a proxy for what the expense accruals should be. In response, AIC argues that one cannot serve as the proxy for another. AIC explains that one is based on actual cash outlays while the other is based on estimates of future claims to be paid. Accrued expense, AIC argues, will not equal cash outlays at any point in time or for any averaging period. But more importantly, AIC argues that cash outlays did not create the accumulated provision that Staff seeks to deduct from rate base. Indeed, if cash accounting was used for reporting this expense, AIC maintains that there would be no accumulated provisions for I&D. For instance, if it kept accounting for OPEB costs on a cash "pay as you go" basis for ratemaking purposes after the adoption of ASC 715-60, AIC asserts that ratepayers would not have funded any portion of accrued OPEB liability recorded for financial reporting purposes. That a normalized level of actual cash claims is used as a substitute for ratemaking purposes for accrued expense does not, AIC insists, demonstrate that ratepayers have provided AIC with funds for future liabilities that AIC has not yet paid.

Staff cites a number of dockets for other utilities where the Commission has deducted the I&D reserve from rate base. AIC observes that in none of the cases was the adjustment contested. But more importantly, AIC points out, Staff fails to identify a single docket where an adjustment to rate base has occurred where the accruals have been eliminated from the revenue requirement and replaced with actual claims paid. For instance, AIC agrees that the Commission reduced rate base in the amount of the I&D reserve in the past two rate cases for North Shore and Peoples, Docket Nos. 07-0241 and 07-0242 (Cons.) and Docket Nos. 09-0166 and 09-0167 (Cons.). The distinction that AIC wishes to make, however, is that I&D expense in those proceedings was set based on expense accruals, not cash claims. In fact, AIC continues, in the only prior case where this proposed adjustment has been contested, the Commission rejected the adjustment because expense for ratemaking was set based on a cash accounting basis. Specifically, in AIC's 2007 rate case, the AG and CUB recommended that the I&D reserve should be deducted from rate base, arguing, as Staff does here, that the reserve represented ratepayer-supplied funds. The Commission rejected the proposed adjustment as unwarranted. AIC reports that the Commission found that while a reserve balance still existed on AIC's balance sheet, it was only for reporting, not ratemaking purposes. AIC states that the Commission accepted its argument then that the use of a cash basis eliminates the need for an adjustment to deduct the reserve. AIC urges the Commission to reject Staff's proposed adjustment in this proceeding for the same reasons, as long as Account 925 accruals are eliminated from the revenue requirement and replaced with an average of actual cash claims paid.

c. Commission Conclusion

The Commission previously addressed this issue in an earlier proceeding concerning AIC's legacy utilities, Docket Nos. 07-0585 et al. (Cons.). In that proceeding, the AG raised arguments very similar to what Staff raises now. In resolving the issue, the Commission found in favor of the legacy utilities and concluded that use of a cash basis eliminates the existence of a reserve balance for ratemaking. The Commission also concluded in that Order that while a reserve balance still exists on the utilities' balance sheets, it is only for reporting, not ratemaking, purposes. Docket Nos. 07-0585 et al. (Cons.), Order (September 24, 2008) at 8-9. The Commission sees nothing in Staff's arguments that would lead it to deviate from its past treatment of this issue. Accordingly, the Commission rejects Staff's position on this issue and adopts AIC's position.

5. PSUP Awards

Under the discussion of operating revenues and expenses, Staff recommends disallowance of 100% of the costs for AIC's Performance Share Unit Program (“PSUP”). Acceptance of Staff's adjustment would necessitate the removal of the capitalized costs of this incentive stock award program. In light of the Commission's conclusion on this operating expense issue, the Commission also directs that the capitalized costs of the PSUP be removed as Staff recommends. The rationale for the disallowance of the PSUP as an operating expense appears below.

V. OPERATING REVENUES AND EXPENSES

A. Resolved Issues

During the course of this proceeding, witnesses recommended various adjustments to AIC's operating revenues and expenses. But upon receiving additional information from AIC, those recommending adjustments sometimes withdrew their suggestions and indicated that they accepted AIC's explanation. For purposes of judicial economy, the Commission does not discuss here instances where a dispute is resolved without any adjustment to the operating revenues and expenses AIC proposed in its direct testimony. Such issues may be found in the parties' briefs. Where the resolution of a dispute or correction of an error, however, resulted in an adjustment to operating revenues and expenses, a list of such adjustments follows.

1. Investment Tax Credits

Investment tax credits are credits against taxes payable related to qualifying plant additions. The credits are generally based on a percentage of the qualifying plant. Regulated public utilities do not treat the decrease to taxes payable as an immediate reduction to income tax expense but treat the tax savings as a deferred credit and amortize the tax savings into income over the life of the plant giving rise to the credits. In its direct filing, AIC did not include the amortization of investment tax credits in its determination of pro forma test year operating income under present rates. On rebuttal, AIC calculated the AG and CUB's adjustment to reduce federal income tax expense for amortization of Investment Tax Credits for each gas Rate Zone. Therefore, no adjustment to AIC's rebuttal position is necessary to incorporate the amortization of investment tax credits into the calculation of pro forma income tax expense. The Commission finds AIC's rebuttal calculations on this issue appropriate and adopts them.

2. Lobbying Costs

Staff witness Tolsdorf proposes an adjustment to remove from AIC's revenue requirement certain lobbying expenses specifically disallowed by Section 9-224 of the Act. AIC accepts Staff's adjustment. The Commission finds this adjustment reasonable and adopts it.

3. Athletic Events Expense

Staff witness Tolsdorf proposes an adjustment to remove from AIC's revenue requirement certain expenditures for athletic events, including the cost of tickets to professional baseball and hockey games. AIC accepts Staff's adjustment. The Commission finds this adjustment reasonable and adopts it.

4. Company Use of Fuels

Staff witness Jones proposes 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. AIC accepts Staff's adjustment. The Commission finds this adjustment reasonable and adopts it.

B. Contested Issues

1. Uncollectibles Expense

a. Staff Position

Pursuant to Section 19-145 of the Act, the Commission may, in a proceeding to review a general rate case, order AIC to prospectively switch from using the uncollectible amount set forth in Account 904 to using net write-offs in the determination of the amount to recover through its Rider GUA-Gas Uncollectible Adjustment, provided that net write-offs are also used to determine the utility's uncollectible amount in rates. The Act provides further that 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 witness Pearce recommends that the Commission order AIC to prospectively switch from using the uncollectible amount in Account 904 to using net write-offs as a percentage of revenues. She is willing to accept AIC's proposal to use a three-year average based on calendar years 2008 through 2010. 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. Staff contends that a switch to the net write-off method would ensure that the calculation of incremental uncollectible expense recoverable through Rider GUA is based on actual accounts written-off and unrecovered instead of estimated amounts. Staff believes that actual information is preferable to estimates since it is more accurate and should be used whenever available. Staff further asserts that Section 19-145 of the Act support its proposal. Staff also cites the Commission's Order in Docket No. 10-0517 (Proposal 1, Order at 3) in support of its position that rates should be determined by individual gas Rate Zone.

Ms. Pearce also proposes a change to the Gross Revenue Conversion Factor ("GRCF") to reflect the uncollectibles percentage for each gas Rate Zone based on a six-year average of net write-offs as a percentage of revenues. She testifies that 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. Ms. Pearce relates that the GRCF adjusts uncollectible expense for the change in revenues at present rates. Therefore, Staff reflects the GRCF based on the percentage of uncollectible revenues for each gas Rate Zone, as presented in Staff's revenue requirement. Staff notes further that the final uncollectibles percentages approved by the Commission in the instant proceeding should be used to update the uncollectibles adjustment in Rider S for Purchased Gas Adjustment ("PGA") supply, and all other tariffs in which the Commission-approved uncollectibles rate is a factor.

b. AIC Position

For purposes of calculating its uncollectibles expense, AIC proposes using the average of actual Account 904 uncollectible expense for the years 2008, 2009, and 2010. AIC contends that this approach is comparable to the amortization periods set in AIC's prior rate cases, Docket Nos. 09-0306 et al. (Cons.) and Docket Nos. 07-0585 et al. (Cons.). AIC understands that no party objects to the use of the annual average of the years 2008 through 2010 to set uncollectible expense. The parties only dispute whether the Commission should order a switch to net write-offs when calculating uncollectible expense, rather than rely on AIC's preferred use of Account 904 uncollectible expense.

AIC asserts that its proposed treatment of uncollectible expense for purposes of determining both the base rate amount and the amounts recovered through Rider GUA is reasonable. AIC states that it is recovering its actual uncollectible costs; no more and no less. AIC acknowledges that the Commission may require a switch to net write offs, but notes that it is not required to. In this instance, AIC asserts that there is no sound reason for making the switch. AIC characterizes Staff's recommendation as a solution in search of a problem.

In support of its position, AIC states that the purpose of establishing rates using a test year is to match revenues with expenses, and to ensure that ratepayers are being charged the cost the utility incurs to provide them service. By switching to the net write-off method, AIC contends that there is a mismatch between the revenues and the uncollectible expense being recorded. According to AIC witness Nelson, under Staff's proposal, the uncollectible expense would be based on the write-offs of receivables for sales and service related to prior periods, not the current period. Although timing differences may occur with riders or other costs trackers, AIC claims that the use of net write-offs causes even more lag between the ultimate reconciliation of expense to the related revenue that caused the expense. During years of volatile gas and electric prices, AIC states that customers could end up paying for high write-offs related to years when they were not AIC customers.

In evaluating this issue, AIC maintains that the important determination is not whether actual experience trumps estimations, but how to establish a representative amount of an expense for the test period so that ratepayers are paying the costs to provide them service. If Account 904 provides a better picture of AIC's uncollectible expense during the time rates are in effect, then AIC believes that it is appropriate to use Account 904 expense to set rates. AIC states further that no witness has testified that use of Account 904 would produce inaccurate results, nor has any witness testified that there would be a mismatch between the revenues and the uncollectible expense being recorded.

With regard to Ms. Pearce's understanding that the Order in Docket No. 10-0517 requires uncollectible rates to be determined by individual Rate Zone, AIC contends that the Order only requires that Account 904 expense be allocated to each Rate Zone for purposes of Rider GUA. Specifically, AIC understands the Order to only require the following language to be added to Rider GUA:

> For the 2010 reporting year, and subsequent reporting years, the annual Account 904 expense amounts shall be allocated to each Rate Zone based on the relative weighting of Account 904 expense by corresponding legacy utility for the period January through September 2010. Order (March 15, 2011) at 3.

Thus, AIC concludes, the Order in Docket No. 10-0517 does not support Staff's position. In contrast, AIC maintains that a single electric and single gas uncollectible rate should be used as recommended by AIC witness Stafford.

c. Commission Conclusion

The Commission understands that there are two issues regarding the determination of uncollectibles in this proceeding: (1) whether the Commission should order a switch to the net write-off method for the calculation of uncollectibles expense and (2) whether a single uncollectibles rate should be utilized. As expressed on many prior occasions, the Commission favors the use of accurate, cost-based rates when appropriate in light of rate impact mitigation concerns. While the use of the balance reflected in Account 904 is not inappropriate, because it is based in part on estimates of uncollectible accounts, the Commission finds that use of net write-offs is more appropriate because the latter method employs actual amounts in its calculation. Consistent with this conclusion, the Commission also finds that Staff's recommendation to calculate separate uncollectible amounts for each Rate Zone is more appropriate. Determining a distinct uncollectible rate for gas service for each Rate Zone is more consistent with the use of cost-based rates and the Order in Docket No. 10-0517. Accordingly, Staff's position on these issues is adopted.

2. Charitable Contributions

AIC proposes to include $775,000 in charitable donations in its gas revenue requirement. Section 9-227 of the Act addresses charitable contributions and provides in full:

> It shall be proper for the Commission to consider as an operating expense, for the purpose of determining whether a rate or other charge or classification is sufficient, donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount. In determining the reasonableness of such donations, the Commission may not establish, by rule, a presumption that any particular portion of an otherwise reasonable amount may not be considered as an operating expense. The Commission shall be prohibited from disallowing by rule, as an operating expense, any portion of a reasonable donation for public welfare or charitable purposes.

Whether the charitable contributions AIC seeks to include in its revenue requirements for the test year are reasonable is contested among the parties.

a. AIC Position

AIC seeks to recover from ratepayers the full amount of the charitable contributions that it anticipates making in the test year. As for their reasonableness, AIC contends that this 2012 budgeted amount is roughly proportional to the $6.1 million that the Commission recently approved for ComEd, which only provides electric service. AIC acknowledges that its 2011 budget for charitable contributions is less, but claims that the lower amount was simply due to economic and budget conditions. Moreover, as a large business with a presence in many communities across the State, AIC argues that many charitable organizations expect and depend upon companies like AIC to support them. AIC also maintains that the effect of its contributions on customers is not significant.

AIC urges the Commission to reject IIEC's recommendation that all charitable contributions be removed from the test year revenue requirements. AIC suggests that

IIEC's position contradicts Section 9-227 of the Act. Similarly, AIC opposes Staff's recommendation that the amount of charitable contributions included in the test year revenue requirements be limited to the 2011 amount, plus a 2% increase. AIC contends that Staff is essentially proposing to deny funds to charitable organizations in AIC's territory, while reducing a residential customer's bill by pennies per month.

b. Staff Position

In Docket Nos. 09-0306 et al. (Cons.), to which AIC refers, Staff accepted and the Commission approved AIC's rebuttal proposal of approximately $406,000 for charitable contributions in the 2008 test year. AIC's charitable contributions budget for 2011 is approximately $1.2 million ($464,000 allocable to gas). AIC's charitable contribution budget for the 2012 test year is approximately $2 million ($766,000 allocable to gas). In comparison to its 2011 charitable contributions budget, Staff points out that AIC is proposing a 65% increase in its 2012 charitable contributions budget. Staff finds this increase unreasonable and recommends that the Commission limit recovery to 2% above AIC's projected budget for 2011.

Staff understands that AIC considers its 2012 budget reasonable because it has every intention of spending that amount. But in Staff's opinion, AIC'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. Staff notes that in Business and Professional People for the Public Interest v. Illinois Commerce Commission, 146 Ill. 2d 175 (1991) ("BPI II"), 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.

Staff maintains that charitable contributions are a discretionary expense and AIC 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.

With regard to AIC's claim of minimal impact on ratepayers from its charitable contributions, Staff avers that AIC fails to consider that rates are based on a multitude of factors and many different expenses. Any one individual expense when allocated across millions of customers may not result in much more than pennies a month. Staff points out, however, that that fact alone does not render a 65% increase in that item reasonable.

Staff observes that ratepayers face difficult economic hardships today. Under AIC's position, Staff notes that ratepayers have no choice whether to contribute to charities or which organizations will receive that benefit. With historically high unemployment, stagnant wages, high and rising energy, healthcare, and education costs, Staff finds it unreasonable to further burden the ratepayer with an increase to the costs of a public utility's charitable contributions, no matter how small. Staff contends that this is especially true when including the greater amount in rates is the very thing that would alleviate the utility's own "economic and budgetary conditions" that precluded it from donating at the higher levels in 2011.

c. IIEC Position

In IIEC's view, AIC's contributions to charity should not be included in its cost of service. In the current economic environment, IIEC argues that no involuntary, compulsory contribution to charities selected by the utility is reasonable. Additionally, according to IIEC, there are other circumstances that impel the Commission to find that AIC's proposed contributions are unreasonable and should not be included in AIC's cost of service. Accordingly, IIEC recommends that the Commission eliminate the entire proposed amount from the electric and gas revenue requirements to be recovered from customers.

First, IIEC makes the observation that the contributions to charity that AIC seeks to recover in this case were originally booked to a below the line account, Federal Energy Regulatory Commission ("FERC") Account 426. IIEC notes that under that circumstance, such expenditures would actually be charitable contributions, since they would come from Ameren shareholders, not recovered through monopoly service rates from others. IIEC contends that this initial below the line treatment is a clear indication that AIC did not view the expense as appropriate for ratemaking consideration. Through a series of accounting entries, IIEC reports that AIC brought the below the line charitable expense totals back into regulated accounts -- then included them in its revenue requirement request for this rate case. Even under the terms of Section 9-227, however, IIEC urges the Commission to find that the budgeted amount is neither a reasonable amount in the current economy, nor appropriate for recovery in just and reasonable rates.

Second, IIEC agrees with Staff that charitable contributions are discretionary expenses, which can be reduced without affecting the utility's ability to provide safe, reliable, and adequate service. Moreover, IIEC observes that just as the elimination of AIC's charitable contributions does not negatively affect service, ratepayer funding of the utility's charitable contributions does not provide enhanced utility service or other benefits to ratepayers. IIEC points out that in contrast to AIC, AIC's customers do not have the same flexibility to reduce their compulsory contributions to charity in AIC's name, enforced through utility bill payments, and (unlike AIC) the core functions of customers' lives are affected by changes in the amount of compelled contributions to AIC's selection of charities.

Third, IIEC contends that the current economic environment for AIC's ratepayers is so challenging that any amount of compulsory "charity" on behalf of a utility is unreasonable. IIEC avers that reasonableness is not an assessment that can be made in a vacuum. Charitable contribution amounts found reasonable in other circumstances need not be accepted as such under all conditions. Though AIC expresses concern about the level of rates it must charge its customers as a result of this rate case, IIEC notes that AIC seeks to recover its charitable donations from its ratepayers, many of whom today may be compelled to rely on charity. Especially during these difficult economic times, IIEC suggests that such discretionary expenses (in any amount) are not reasonably imposed on ratepayers.

IIEC acknowledges that the Commission has not followed its recommended course in the past. IIEC points out, however, that the Commission's determinations of reasonableness in prior cases are, as a matter of law, not binding in this case. Mississippi River Fuel Corp. v. Illinois Commerce Comm., 1 Ill. 2d 509 (1953) at 513. The Commission's findings of fact must be based on this record alone. IIEC contends that the record in this case is significantly different from prior records. The record in this case, IIEC maintains, reflects the realities of an economic environment that is unique in recent times. IIEC does not deny that its recommendations would be a departure from past Commission decisions but claims that it is equally undeniable that the economic conditions faced by AIC's customers are also a departure from anything the Commission has reviewed under the current statute.

Furthermore, IIEC asserts that AIC's arguments in testimony closely track the language of Section 9-227 in most respects. According to IIEC, however, Ameren Ex. 28.1 lists only the recipients of planned contributions and categories of activities with which those recipients are associated. The exhibit does not contain information from which the Commission can verify that the contributions are made "for the public welfare" or another permissible purpose. Pursuant to Section 9-201(c) of the Act, IIEC states that such information is part of the utility's burden of proof, it is not a responsibility of any other party to show the contrary. The gist of Section 9-227, IIEC argues, is to require an examination of proposed expenses, as opposed to categorical distinctions between allowed and disallowed contributions. Yet, IIEC continues, AIC approaches this issue as though the utility is entitled to recover expenses that are reasonable according to a categorical comparison to what another utility was able to recover.

d. GCI Position

GCI supports Staff's adjustment to AIC's proposed charitable contributions for the test year. GCI concurs that a forecasted 65% increase in the test year over 2011 contributions is unreasonable. Charitable contributions are a discretionary expense not necessary for the provision of safe and reliable service. GCI agrees with Staff that during these challenging economic times, AIC's obligation is to provide safe and reliable service at the most reasonable rate possible. GCI observes that AIC claims that the 65% increase is warranted because it desires to increase contributions, but in 2011 was under economic and budget constraints that did not allow it to contribute at the level it wanted. But at present, GCI notes that AIC's customers are under similar constraints, and are without the same flexibility when it comes to paying their utility bills.

GCI agrees with IIEC that including charitable contributions in cost of service makes ratepayers involuntary contributors to charitable organizations chosen by the utility. This is especially difficult, GCI adds, during these difficult economic times. But GCI notes that IIEC's position of disallowing 100% of charitable contributions is a departure from past Commission practice. At a minimum, GCI urges the Commission to adopt Staff's adjustment and limit recovery of charitable contributions to 2% above 2011 levels.

e. Commission Conclusion

The Commission observes that during the 2012 test year, AIC anticipates making contributions of approximately $2,000,000 ($775,000 allocable to gas) to schools and universities, disease research organizations, multiple chambers of commerce, hospitals, a county fair, the Illinois State Fair, a hockey team, the United Way, and multiple other entities. See Ameren Ex. 28.1. Whether such contributions are appropriate, particularly in the current economic climate, is of some dispute. Section 9-227 provides that,

> It shall be proper for the Commission to consider as an operating expense, for the purpose of determining whether a rate or other charge or classification is sufficient, donations made by a public utility for the public welfare or for charitable scientific, religious or educational purposes, provided that such donations are reasonable in amount.

The provisions of Section 9-227 make clear that charitable contributions are a recoverable expense. The Commission understands that it must also "determine the reasonableness of the amount of contributions based on the total contributions rather than on an individualized basis." BPI II, 146 Ill.2d at 255.

In making a determination of reasonableness, the Commission agrees with IIEC that reasonableness is not an assessment that can be made in a vacuum. Charitable contribution amounts found reasonable in some circumstances need not be accepted as such under different circumstances. Weighing on such a determination is the fact that charitable contributions are discretionary expenses, which can be reduced without affecting the utility's ability to provide safe, reliable, and adequate service.

The IIEC proposes to eliminate all charitable contributions from AIC's revenue requirement. The IIEC argues that "the current economic environment for Ameren's ratepayers is so challenging that any amount of compulsory "charity" on behalf of a utility is unreasonable." IIEC Init. Br. at 9. Not only is IIEC's position a departure from the Commission's past treatment of charitable contributions, it fails to take into account that in times of economic hardship there is an even greater need for charitable help. Charitable contributions are important societal engines that provide welfare to communities. As such, the Commission rejects IIEC's position on this issue.

The Commission is cognizant of the difficult economic hardships ratepayers are facing. As Staff notes, ratepayers are experiencing historically high unemployment, stagnant wages, high and rising monthly bills, and rising healthcare and education costs among other factors. Under the current economic climate, the Commission is concerned that AIC has not justified its full $775,000 in anticipated charitable contributions in 2012. First, the Commission notes that by its own admission AIC reduced its charitable contributions in the past when its financial resources were constrained. AIC now apparently foresees a sufficiently improved financial situation to significantly increase discretionary donations (and gain the associated goodwill and positive publicity) with the expectation that ratepayers will provide the entire amount of the donations. The Commission is concerned that AIC's proposal would seem to reverse its decision to decrease charitable contributions when the full cost could not be effectively passed along to its ratepayers. For AIC to now expect others, some who may be in financial distress, to fund its donations in the name of charity is troubling to the Commission. To quote AIC when discussing its own financial concerns, "[e]very dollar will make a difference." AIC Init. Br. at 1.

To be perfectly clear, the Commission by no means intends to suggest that AIC cannot or should not make any of the donations that it proposes. AIC and Ameren are free to make any such donations. But because of the overall economic climate, the Commission cannot conclude that the full amount should be passed through to ratepayers. The Commission recognizes that the individual impact on ratepayers is small, but as the Commission has held before, it is not the reasonableness of individual elements of bills that concern ratepayers, it is the total amount. A 65% increase in recoverable charitable contributions from ratepayers during the current economic climate is untenable. As such, the Commission finds that Staff's proposal to limit recovery of charitable contributions at the Company's 2011 budget plus a 2% increase is more reasonable. Accordingly, the Commission adopts Staff's position on this issue.

3. Injuries and Damages Expenses

Staff, AG/CUB, and AIC agree that test year I&D expense should be adjusted to remove the test year accrual for claims to be paid. They also agree that the accrual should be replaced with a historical average of actual claims paid for the five year period 2006-2010. This is consistent with the approach approved by the Commission in AIC's last three rate cases. Where the position of AG/CUB and AIC deviates from that of Staff is whether the non-accrual portions of I&D expense should be normalized.

a. AIC Position

In arguing against normalizing the non-accrual portion of I&D expense, AIC points out that the Commission has not done so in any of the past three AIC rate cases. Nor, AIC argues, has Staff demonstrated that the non-accrual portion is an expense that should be normalized. AIC recommends that Staff's adjustment to normalize the entire amount of the expense in Account 925 should be rejected. AIC suggests that the

Commission use the amount of I&D expense agreed to by AG/CUB and reflected in AIC's schedules as presented on rebuttal.

In recent Commission orders setting electric and gas rates for AIC dating back to at least the Order in Docket Nos. 06-0070 et al. (Cons.), AIC notes that the Commission has normalized only the cash claims portion of I&D expense after elimination of the Account 925 expense accruals. AIC claims that both it and Staff recognized in the 2006 rate case that because cash payments can fluctuate greatly from year to year, it is appropriate to use a normal level of annual claims paid as the substitute for the expense accrual. Both the reserve accruals and the corresponding cash claims paid, AIC contends, have continued to fluctuate dramatically in the past five years. In contrast, AIC continues, the second largest component of I&D expense (liability and workers compensation insurance expense) historically is not a volatile expense. Without evidence of volatility for a particular expense item, AIC argues that there is no basis to normalize. AIC and AG/CUB's approach replaces the expense accruals with a normalized level of cash claims paid to develop the overall level of I&D expense recorded to Account 925. Staff's approach, on the other hand, normalizes the entire account and changes the test year expense for the entire account to a historical average. Although there is a basis (and agreement amongst the parties) to normalize the accrual portion of Account 925 based on the volatility of cash claims paid, AIC asserts that there is no such basis to normalize all expense booked to this account.

In response to Staff's suggestion that AIC has not justified the increase in projected test year I&D expense less the expense accruals, AIC contends that Staff has not pointed to any evidence other than the percentage change for projected non-accrual expense for Account 925 in support of its normalization proposal. More importantly, AIC insists, Staff's calculation of the electric percentage increase and gas percentage decrease for non-accrual Account 925 expense does not take into account the corrections AIC made to the allocation of I&D expense to gas and electric operations made in supplemental testimony. Rather, AIC observes that Staff's calculation used the original test year forecast for electric I&D expense (which was overstated) and the original test year forecast for gas I&D expense (which was understated). Thus, AIC states that there is not even any record evidence of the actual percentage change in projected non-accrual Account 925 expense.

b. Staff Position

Staff urges the Commission to accept its adjustment to normalize I&D for the entire expense rather than just a portion of the expense. While AIC proposes to normalize only the expense accruals portion of the I&D expense, Staff points out that 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. According to Staff, AIC 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. Staff acknowledges AIC's supplemental testimony indicating that AIC had incorrectly allocated some I&D expenses for the forecasted test year between gas and electric. Staff contends that a review of AIC witness Stafford's rebuttal revenue requirement schedules, however, indicates that the adjustments mentioned in the supplemental testimony are not reflected in the revenue requirement schedules. Staff maintains that the uncertainty introduced from AIC'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.

c. IIEC Position

IIEC found AIC's proposed expense level excessive._Based on the testimony of IIEC and other intervenors, IIEC relates that AIC corrected and revised its test year I&D expense proposal in its rebuttal testimony. AIC's revised amount reflects a reduction of approximately $2.3 million. While IIEC acknowledges that other issues raised by Staff remain unresolved, the revision proposed by AIC resolves the issues raised by IIEC on this issue.

d. Commission Conclusion

Having reviewed the arguments, the Commission is not persuaded that the record supports a change from past practice on this issue. If Staff wishes to renew its arguments with additional evidence in future rate proceedings, the Commission will consider such arguments then. But for purposes of this proceeding, the Commission adopts AIC's position.

4. Merger Costs

a. AIC Position

AIC has included in the test year revenue requirement approximately $2 million of operations and maintenance ("O&M") savings and $728,000 of O&M costs related to the merger of the legacy utilities on October 1, 2010, as determined through a comprehensive and detailed study of merger costs and benefits, the MIPO study. In addition, AIC has included in test year rate base approximately $704,000 of capital cost savings and $235,000 of capital costs related to the MIPO study, which are not contested. AIC urges the Commission to approve recovery of all of these amounts.

AIC explains that its rate-making treatment reflects the amortization over a four-year period for the merger costs, in the amount of $728,000 per year, which recognizes that savings from these initiatives will continue to accrue to ratepayers in future rates. AIC has reflected estimated test year savings from 2011 and 2012 merger initiatives in the 2012 test year forecast and proposes that future savings from merger initiatives would accrue to ratepayers in subsequent rate cases, net of related costs incurred to realize such savings. These amounts also reflect a correction to remove from the merger costs certain internal labor amounts, made by AIC on rebuttal.

AG/CUB witness Effron proposes an adjustment in the amount of approximately $500,000 to remove merger O&M costs from the test year. The basis for his adjustment, as AIC understands it, is that the merger costs are entirely estimates of costs that AIC expects to incur in 2011 and 2012, and so it is not appropriate to reflect the amortization of the costs in the revenue requirement before those costs are actually known. AIC contends that Mr. Effron's position appears to ignore AIC's use of a future test year, and so should be rejected. Because it is utilizing a future test year, AIC argues that its costs are based on a projection or forecast of the future period. Thus, AIC contends that the use of projected savings for merger costs and benefits is appropriate. Further, AIC states that the MIPO represents a detailed study of projected merger costs and benefits that support the projected future costs and benefits of the merger. Given this study supporting the merger costs, AIC asserts that Mr. Effron's position should be disregarded. Finally, even if the Commission were to agree with Mr. Effron, AIC claims that Mr. Effron's adjustment has ignored the savings side of the equation. If costs and savings are unknown, AIC suggests that the appropriate remedy would be to remove from the revenue requirement both the test year merger costs ($500,000, as proposed by Mr. Effron) and the test year merger savings of $2 million (as also too indefinite under his analysis). AIC states that this would result in an increase to AIC's revenue requirement of approximately $1.5 million.

b. GCI Position

Until the actual amount of costs to be recovered is known and until it can be established that expected savings from the merger are actually being realized, GCI argues that there should be no recovery of merger costs. GCI states that the merger costs proposed by AIC are estimates of the costs AIC expects to incur in 2011 and 2012. GCI notes that AIC claims to have experienced $1.27 million dollars of savings related to the merger, which it has included in test year O&M expense and supposedly reflected in Account 903, Customer Record and Collection Expenses. Mr. Effron found that it was not clear that AIC's 2012 forecast for that account actually incorporated the savings claimed by AIC. On rebuttal, AIC eliminated the deferral and amortization of internal labor costs related to the merger from its request. GCI reports that Mr. Effron therefore reduced his adjustment accordingly, which resulted in an adjustment of $503,000 for gas.

c. Commission Conclusion

Given its use of a future test year and the record on this issue, the Commission is satisfied that AIC has accurately reflected its merger costs and savings in its test year operating expenses. GCI's arguments do not persuade the Commission to conclude otherwise. Accordingly, the Commission adopts AIC's position on this issue.

5. State Income Tax Expense - Regulatory Asset

a. AIC Position

Effective January 1, 2011, the State of Illinois increased the state corporate income tax rate by 2.2%. AIC proposes to reflect the increase prospectively in utility rates set in this proceeding, and to recover the effect of the tax rate increase experienced before new utility rates go into effect (essentially, the increased 2011 liability) by amortizing that amount over the expected life of the new rates. Specifically, AIC seeks to recognize a regulatory asset, which would be amortized over a two-year period beginning January 1, 2012. While Staff agrees that the state tax rate increase should be recovered prospectively, it opposes AIC's request to recover the impact of the tax hike experienced before new utility rates go into effect.

AIC argues that Staff's position is inconsistent with what the Commission has done when income tax rates decrease. Pursuant to the Tax Reform Act of 1986 ("TRA"), the federal corporate income tax rate decreased from 46% to 34%. AIC reports that the Commission quickly required utilities to either file new tariffs reducing base rates, file TRA rate riders that would collect rates subject to refund to reflect the reduced tax rate, or face rate reduction proceedings. All utilities complied with the Commission's directive in one form or another. AIC states that one of its predecessor companies, Central Illinois Public Service Company, ultimately refunded tens of millions of dollars to customers pursuant to its electric and gas TRA riders.

AIC now seeks regulatory treatment that is symmetrical with the Commission's early action regarding a change in tax rates. One of the Commission's important roles, AIC states, is to assure that rates fairly reflect the interests of utilities and customers alike. AIC argues that a policy that always favors customers is not symmetrical, fair, or reasonable, and is unlikely to be viewed favorably by investors, upon whom the utility companies (and by extension, their customers) rely. Accordingly, AIC believes that it should be permitted to set up and recover a regulatory asset over a two-year period beginning January 1, 2012.

b. Staff Position

Staff proposes adjustments to reduce AIC's gas operating expenses for the deferred state income tax expense from 2011. Staff argues that the regulatory asset represents deferred expenses incurred outside of the test year and is therefore unreasonable to include in the 2012 test year. Because AIC's proposal involves a single cost from outside of the test year, Staff contends that the proposal raises the specter of single issue ratemaking since it involves including non-test year expenses in the revenue requirement in a case with a future test year. Staff asserts that 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, Staff avers, deferral of operating expenses for later recovery would violate the Commission's test year rules as established in BPI II by allowing recovery of these operating expenses outside of the test year.

In support of its position, Staff points out that in Docket No. 98-0895, 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 (March 15, 2000), Section IV.

In that Order, Staff observes that the Commission cited BPI II, which found that recovery of operating expenses outside of the test year violates test year principles. See BPI II 146 Ill.2d at 240-241. Staff states further that the Commission's Order in Docket No. 98-0895 also cited Docket No. 93-0408, a rulemaking proceeding regarding the deferral of costs:

> 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 March 15, 2000), Section IV.

In Docket No. 93-0408, Staff relates that 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 (October 19, 1994) at 2.

Staff also argues that the fact that this increased expense was caused by a change in the state income tax rate does not alter the fact that it is an out-of-test year period increase, no different than if AIC's wages were higher in 2011 than in its last rate case. Staff states further that 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. On the contrary, Staff observes, the income tax rate for corporations was simply raised from 4.8% to 7.0% without discussion of the impact on Illinois utilities nor any change in Commission authority regarding such additional tax. See 35 ILCS 5/201 (b)(8) and (10). Moreover, Staff asserts that other expenses may be decreasing enough to offset the magnitude of the tax 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 a company's financial position, not just isolated increases. Staff adds that 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.

In response to AIC's suggestion that it had no opportunity to alter utility rates before the change in tax rate went into effect, Staff notes that if AIC 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 Section 287.40 of Part 287. No deferral or regulatory asset would have been created since the test year would already include the 2011 increased tax at issue here. Because the court rulings and Commission orders on the subject of rate recoverability of deferred operating expenses are not new, Staff contends that AIC should have been aware of the consequences of the rate recoverability of its increased 2011 state income tax expense.

Additionally, Staff contends that AIC misrepresents the Commission's past practice with regard to the TRA in 1986. Staff states that the TRA orders pertaining to AIC's former operating utilities show that the Commission required a revenue requirement analysis for each utility prior to any ratemaking change taking place. Staff explains that there was no simple, standard Commission practice as AIC's testimony implies. Staff also notes that not all utilities changed their rates due to the tax decrease, including the former Central Illinois Light Company and Central Illinois Public Service Company gas operations.

Staff also denies that its adjustments always favor customers. As an example of an adjustment benefitting AIC, Staff points to a correction it suggested to AIC's ADIT that increased AIC's rate base and, therefore, was a benefit to AIC, not ratepayers. Staff maintains that its position on AIC'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.

c. GCI Position

GCI objects to AIC's proposal to establish a regulatory asset pertaining to the increase in the state income tax rate. To do so, they contend, would selectively and unfairly recognize a change that increases AIC's revenue requirement without concomitant recognition of changes that decrease its revenue requirement. All other things equal, GCI recognizes that an increase in state income tax rate would increase AIC's revenue requirement. But all other things are not equal, GCI observes, because in 2011, bonus tax depreciation equal to 100% of qualifying plant additions is available to AIC. This bonus depreciation, GCI explains, reduces AIC's cost of service in 2011 through ADIT, and the revenue requirement effect of the bonus depreciation is substantially greater than the revenue requirement effect of the state income tax rate increase. GCI also rejects AIC's argument that symmetry calls for recovery of the non-test year tax expense. GCI states that AIC chose a 2012 test year, and it cannot pick and choose certain expenses from other years to include. GCI insists that AIC should be required to follow the rules of the test year it chose, both the freedoms and constraints, on an equal basis.

d. IIEC Position

IIEC calculates that the effect of adopting AIC's position on this issue would be to increase test year costs by $494,000 for gas operations. IIEC recommends that the Commission reject AIC's proposal and raises arguments echoing those of Staff and GCI. IIEC points out that AIC's 2011 tax expense could have been offset by other expense decreases and contends that the effect on AIC is not so significant as to warrant special treatment. Nor, IIEC continues, does the fact that the tax expense increase was beyond AIC's control change the fact that it is simply another out-of-test year expense increase, no different from an increase in wages in a year the utility did not propose as its test year. Ultimately, IIEC views AIC's proposal as yet another instance of a utility choosing an advantageous test year, then reaping the benefits of that choice while trying to avoid its consequences. AIC had an opportunity to select a test year that would have legitimately included the 2011 tax expense increase. IIEC states that AIC chose a different course, however, and now asks the Commission to pretend it did not and to transfer the financial consequences of its decision to its ratepayers. IIEC concludes that the requested inclusion of the out of test year expenses in AIC's test year revenue requirement is unlawful and cannot be allowed.

e. Commission Conclusion

AIC recommends that the Commission allow it to include in its 2012 test year the increase in its 2011 Illinois income tax. All parties recognize that doing so is generally inconsistent with the test year rules. AIC, however, contends that it is only right to do so because in 1986, when the relevant federal income tax rate fell by 12%, the Commission required utilities to reflect the tax reduction in rates.

The Commission has considered AIC's request for special treatment relating to income taxes and has concluded that it does not share AIC's view. With regard to the 1986 federal tax reduction, the Commission required a revenue requirement analysis for each utility prior to any ratemaking change taking place. Therefore, the process in 1986 was not as simple as AIC suggests. In fact, only one of the three legacy utilities actually reduced its electric and gas rates as a result of the income tax rate reduction.

In addition, AIC does not appear to have taken into account any decreases in expenses during 2011 that may have offset the state income tax rate increase. GCI insists that such an offset in fact exists and references bonus tax depreciation. Looking at only one expense out of many in any given year is inappropriate and amounts to single-issue ratemaking. As noted above, this is specifically what the Commission did not do in association with the 1986 income tax rate reduction. Contrary to AIC's suggestion, an increase in 2011 state income tax rates is no different than any other expense incurred by AIC.

Moreover, not recognizing a 12% decrease in the federal income tax rate would have amounted to a windfall to utilities. The increase in the state income tax rate is much smaller, having only increased from 4.8% to 7.0%, for a change of 2.2%. It appears that the overall impact on AIC is not significant. In fact, if this change had a greater impact on AIC, it could have chosen a different test year. Accordingly, the Commission will uphold the test year rules and rejects AIC's position.

6. PSUP Awards

AIC requests recovery of 50% of the test year cost of its PSUP. The requested amount is $483,000 in operating expenses and $197,000 in utility plant. AIC characterizes the PSUP is an integral component of its executive compensation, and awards certain executives the right to receive a share of Ameren common stock, a "Performance Share Unit." PSUP awards are based on achievement of performance criteria relating to Ameren's total shareholder return ("TSR") relative to a utility peer group and AIC's earnings per share ("EPS") over a set number of years. The stock amount, however, does not vest for three years, and will not vest at all in the event of termination for cause. Whether AIC should be allowed to pass along to ratepayers the cost of the PSUP is in dispute.

a. AIC Position

According to AIC witness Bauer, the primary objective of the PSUP is to encourage AIC's executives to remain with AIC and focus their efforts on its long-term success. Moreover, she contends that the multi-year time frame and stock award distinguish the PSUP from AIC's annual, short-term, cash incentive compensation plan. AIC claims that the PSUP benefits Illinois ratepayers in several ways. First, by encouraging executives to remain, such experienced executives benefit customers through their knowledge of the industry in general and of AIC specifically. AIC also claims that they promote efficiency and effectiveness in their respective lines of work. Thus, by encouraging longevity, AIC contends that the PSUP promotes competency.

In addition to promoting executives' longevity with AIC, Ms. Bauer testifies that the PSUP improves AIC's ability to recruit capable employees. She indicates that long-term stock award programs are common among AIC's utility peers and are accepted in the industry as an important tool in acquiring top executive talent. Without a plan with the design of the PSUP, she fears that executive positions within AIC would be less attractive to candidates. Because the PSUP benefits AIC, she suggests that it also benefits customers.

To achieve long-term success, AIC also argues that executives under the PSUP must support cost management and cost control measures. AIC believes that it and its ratepayers benefit from such objectives as well. In AIC's last rate case, Docket Nos.

09-0306 et al. (Cons.), the Commission instructed AIC to consider the benefits to both ratepayers and shareholders resulting from cost management and cost control measures with respect to AIC's short-term incentive compensation plan. With this mind and because the PSUP benefits both AIC and its customers and necessarily encourages consideration of cost management and cost control measures, AIC proposes partial recovery—50%—of its PSUP cost. In other words, given the PSUP benefits both ratepayers and shareholders, AIC suggests that both share equally the cost of the program.

While conceding that the PSUP provides some level of benefit to ratepayers, AIC notes that Staff opposes AIC's 50/50 sharing proposal on the grounds that the program aligns employee interests with those of shareholders and allegedly provides no "direct ratepayer benefit"—the standard applicable to recovery of short-term incentive compensation plan expense. AIC disagrees with Staff's recommendation that shareholders cover all of the cost of the PSUP. AIC's first counterpoint to Staff's position is simply that the PSUP is not a short-term incentive compensation plan. As such, AIC argues that the "direct ratepayer benefit" standard (applicable to short-term incentive compensation plans) that Staff witness Pearce refers to is not the appropriate standard under which to consider the PSUP. Rather, Ms. Bauer suggests, apart from the most apparent distinction—awards are made in stock, and not in cash—the PSUP differs from short-term incentive compensation plans. Unlike short-term incentive compensation plans, she reiterates that the primary objective of the PSUP is to attract, motivate, and retain AIC leaders by providing a competitive total compensation package that serves as a counterbalance to short-term incentive compensation. Further, unlike short-term incentive compensation plans, under which cash compensation is distributed annually, Ms. Bauer states that the PSUP entails a three-year vesting period which encourages AIC executives to remain with AIC. Moreover, she believes that it is noteworthy that the 2008 PSUP incorporates an additional two-year holding period—Performance Share Units are awarded five years before the award of any common stock. As a result of these differences, AIC contends that the "direct ratepayer benefit" standard is not applicable. But even if the same standard applies to the PSUP, AIC asserts that it is appropriate to include in rates a portion of the PSUP.

AIC acknowledges the similarities of this issue with one addressed by the Commission in ComEd's rate Order in Docket 05-0597. In that Order, the Commission disallowed recovery of the expense of the portion of ComEd's incentive compensation plan related to an EPS metric. See Docket No. 05-0597 Order (July 26, 2006) at 96. AIC believes that the ComEd Order is distinguishable. Not only was ComEd's plan in Docket No. 05-0597 a short-term incentive (cash) compensation plan, AIC notes that the ComEd Order did not concern a 50/50 sharing proposal like AIC is suggesting here. Rather, ComEd sought complete recovery of its incentive compensation plan, including the EPS funding metric, through rates. AIC is not seeking recovery of the portion of its incentive compensation plan tied to an EPS metric.

b. Staff Position

Based on AIC's description of the PSUP, Staff concludes that the PSUP basically rewards AIC's executives for AIC's financial performance and aligns the interests of executives with shareholders. Because AIC has not demonstrated that this incentive program provides any direct benefit to AIC ratepayers, beyond the incentive for employees to stay with AIC that is created by the relatively longer vesting period, Staff considers it inappropriate to pass any of the PSUP costs on to ratepayers.

In support of its position, Staff explains that the PSUP is based on financial targets like EPS. According to the PSUP program concept described in AIC's response to 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 [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 contends that 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.

Staff relates that the Commission has a well-established standard for assessing recovery of incentive compensation costs. In Docket Nos. 09-0306 et al. (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 No. 09-0306 et. al. (Cons.) Order (April 29, 2010) at 83.

Staff observes that costs associated with the PSUP are not necessary for the provision of utility service, and given AIC's failure to demonstrate direct ratepayer benefits, Staff asserts that these costs should be disallowed in their entirety.

Staff is not persuaded by AIC witness Bauer's argument that the retention of more experienced executives represents sufficient direct benefit to ratepayers to warrant ratepayers contributing to the cost of the PSUP. Although the PSUP may provide some tangential ratepayer benefits as described by Ms. Bauer, Staff asserts that this plan is designed primarily to benefit shareholders, which is why the AIC executives are compensated with shares of Ameren stock instead of cash. Because shareholders are the primary beneficiaries of the PSUP, Staff contends that they should bear the entire cost. In support of this position, Staff cites Docket No. 05-0597 in which the Commission found that the portion of ComEd's incentive compensation plan that was based on an EPS metric should not be recovered through rates because the primary beneficiaries of increased EPS are shareholders, not ratepayers. Docket No. 05-0597 Order (July 26, 2006) at 96. 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.

On appeal, Staff reports that 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." ComEd also asserted, AIC observes, that a financially healthy utility can obtain needed financing at a lower cost, which would lower customer costs. At oral argument, the Order notes that ComEd suggested the incentive plan benefited ratepayers by attracting good employees that raised the level of service customers receive. Staff relates that the Appellate Court concluded that such a benefit is too remote. Docket No. 05-0597 Order (September 17, 2009) at 12–13. Staff points out that the types of tangential customer benefits described in 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.

c. GCI Position

GCI supports Staff's adjustment to disallow 100% of the expense associated with the PSUP. GCI observes that incentive compensation costs are recoverable in rates only if the plan confers upon ratepayers specific dollar savings or other tangible ratepayer benefits. If simply attracting and retaining qualified executives, which AIC identifies as the primary purpose of the PSUP, was enough to be determined a "customer benefit," as required by the Commission, then according to GCI any and all incentive compensation plans could arguably be recoverable. GCI asserts that retaining qualified employees has no specific dollar savings, nor does it provide ratepayers a tangible benefit. Instead, GCI contends that the PSUP rewards executives for AIC's financial performance, thereby aligning the interests of executives with shareholders. GCI also points out that the PSUP can reward employees when AIC is allowed rate increases by the Commission, which is strictly a shareholder benefit. GCI further observes that the program is based on financial targets similar to the EPS metric disallowed by the Commission in Docket No. 05-0597.

d. Commission Conclusion

The Commission has reviewed the record on the PSUP and is reluctant to allow even partial recovery from ratepayers of the associated costs. Primarily, the Commission does not perceive any benefit to ratepayers from PSUP awards, which are based on the achievement of performance criteria relating to Ameren's TSR and AIC's EPS. All else equal, having experienced, trained executives benefits AIC and rewarding them if the Company's value increases is logical. But it appears to the Commission that the primary trigger (if not the only trigger) leading to an award of Ameren common stock is tied to the Company's financial bottom line rather than enhanced service to ratepayers, not unlike the situation in Docket No. 05-0597. The fact that ComEd sought 100% recovery from ratepayers for its incentive compensation plan does not render it irrelevant to the current circumstances. Whether it is 1% or 100% proposed recovery of a financial performance based award, the Commission cannot justify passing on to ratepayers expenses for an incentive compensation plan that does not provide an overall benefit to them. If the loosely connected customer benefits were considered sufficient, then as GCI suggests, any and all incentive compensation plans could arguably be recoverable. Nothing in this conclusion prohibits AIC from continuing the PSUP, but given the lack of perceptible benefits for customers, the Commission cannot require customers to pay for the program. Accordingly, the Commission adopts Staff's position on this issue.

7. Rate Case Expense

The expenses that a utility incurs in preparation and litigation of a rate case are addressed in Section 9-229 of the Act and Section 285.3085 Schedule C-10 of Part 285. Section 9-229 provides in full:

> Consideration of attorney and expert compensation as an expense. The Commission shall specifically assess the justness and reasonableness of any amount expended by a public utility to compensate attorneys or technical experts to prepare and litigate a general rate case filing. This issue shall be expressly addressed in the Commission's final order.

Section 9-229 became effective on July 10, 2009. Section 285.3085 provides in full:

a) Provide detail of the total projected expenses associated with the instant rate case as to those expenses that the utility is seeking to recover in its proposed rates. The detail shall include the expenses of the instant rate case and the amount included in test year jurisdictional operating expense at proposed rates on Schedule C-1 for the following categories:
   1) Outside consultants or witnesses;
   2) Outside legal services;
   3) Paid overtime;
   4) Other expenses; and
   5) Total expense.
b) The information provided for each outside consultant or witness and each outside legal service shall include:
   1) Name;
   2) Estimated fee;
   3) Basis of charge;
   4) Travel expenses;
   5) Other expenses;
   6) Projected total expenses of instant rate case;
   7) Type of service rendered;
   8) Specific service rendered; and
   9) Amount included in test year jurisdictional operating expense at proposed rates on Schedule C-1.
c) Provide by footnote:
   1) A description of the costs associated with the category, other expenses; and
   2) An explanation of the calculation of the costs associated with the category, paid overtime.
d) If amortization of previous rate case expenses are included within test year jurisdictional operating expense at proposed rates on Schedule C-1, provide the amount of amortization expense associated with each rate case by docket number.

AIC requests recovery in rates of $3,341,759 for outside legal and technical experts. AIC proposes to amortize this amount over two years. AIC presented information in support of this requested level of rate case expense in Ameren Ex. 40.13. In response to an Administrative Law Judges data request, AIC reports that it paid $546,463.31 to attorney and technical experts that it employs for work they performed to prepare and litigate both the gas and dismissed electric rate proceedings. Ameren Ex. 54.0 consists of AIC's response to the Administrative Law Judges' data request.

AIC and Staff both recommend that the Commission expressly find that the amounts that AIC proposed, as adjusted by Staff, to be expended to compensate attorneys and technical experts to prepare and litigate this proceeding are just and reasonable pursuant to Section 9-229 of the Act. Staff recommends that the Commission make the following finding in its 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).

The Commission notes that, in light of the relatively recent enactment of Section 9-229 and the related issues raised in recent rate cases, the Commission is taking a closer look at rate case expense. On November 2, 2011, the Commission initiated a rulemaking in Docket No. 11-0711 to allow all interested parties to participate in formulation of rules regarding the issue of rate case expense. The rulemaking will establish clear criteria, procedural and evidentiary standards to justify attorneys' and expert compensation under Section 9-229 of the Act. The Commission's intention for initiating the rulemaking in Docket 11-0711 is succinctly stated in its initiating Order, which provides in pertinent part:

> A rulemaking is an appropriate vehicle for this, as the Commission's intent is that this will establish a general policy for the Commission, as opposed to a pronouncement in a rate case that will only affect a single utility.

Given the timing of the rulemaking proceeding that has begun and the case herein, the Commission is without the benefit of those new standards. Nevertheless, the Commission is cognizant that a thorough analysis of these costs is required in order to approve such costs under Section 9-229 as well as the recent Court opinion. The Commission observes that the instant record shows the issue of rate case expense was a resolved issue by all parties, uncontroverted and undisputed in the record until the Briefs on Exceptions. During discovery, rebuttal and surrebuttal testimony, AIC presented extensive information in support of its requested level of rate case expense, including information regarding amounts expended to compensate attorneys and technical experts. Notably, AIC provided information regarding its projected level of rate case expense in compliance with Rule 285.2085, 83 Ill. Adm. 285.2085, which included billing rates for outside consultants and attorneys and the associated breakdown of time spent by those individuals necessitated by the rate case, monthly updates of rate case expense incurred, and narrative responses addressing the reasonableness of each rate case expense component. The information provided in Ameren Ex. 40.13 shows the amount of rate case expense actually incurred by the Company as of June 2011.

Furthermore, in response to the Administrative Law Judges' data request regarding compensation to technical experts and attorneys employed by AIC or its affiliates, AIC provided even more information in Ameren Ex. 54.0 regarding rate case expense by listing the in-house attorneys and technical experts and the estimated compensation paid to each of those employees.

As mentioned above, the Commission is aware of a recent Appellate Court decision wherein the Appellate Court remanded the issue of rate case expense finding that the Commission analysis should be reflective of its in depth review concerning attorney and expert compensation, related to the rate case expense, in order to meet the new statutory requirements contained in Section 9-229 of the Act. People of the State of Ill. v. Ill.C.C., et al; Illinois-American Water Co. V. Ill.C.C., et al., 2011 Ill App (1st) 101776, Opinion of December 9, 2011, Ill.C.C. Docket No. 09-0319. In the underlying case, Docket No. 09-0319, some parties argued that the rate case expense was too large in cumulative terms. This matter is clearly distinguishable as those allegations are not part of the record in the instant docket. Rate case expense, as adjusted by Staff, was not disputed on the grounds that the expense was too large. Moreover, in this proceeding the Commission has undertaken the type of diligent analysis of the supporting evidence for rate case expense as proscribed by the Court in its recent decision.

The Commission notes that the amount of rate case expense was not an issue raised by any party to this proceeding. We reviewed the evidence provided in the record by AIC and conclude that the Company provided ample and credible information to enable us to make a finding that the rate case expense is just and reasonable. Having reviewed the record, the Commission finds AIC's requested recovery of rate case expense, as adjusted by Staff, is just and reasonable pursuant to Section 9-229 of the Act and should be approved. The Commission also adopts AIC's proposal to amortize rate case expense over two years to be reasonable and that proposal is adopted.

VI. COST OF CAPITAL/RATE OF RETURN

A. Overview

A company utilizes various types of investor-supplied capital to purchase assets and operate a business. Utilities typically rely upon long-term debt and common equity, and in some instances preferred stock and short-term debt, to purchase assets and fund operations. The costs of different types of investor-supplied capital vary depending upon a multitude of factors, including the risk associated with the investment. As a result, the proportion of the different types of capital, also known as the capital structure, when combined with the costs of each different type of capital affects the overall or weighted average cost of capital, which is the ROR a utility is authorized to earn on its net original cost rate base.

The Commission relies on the cost of capital standard to determine a fair ROR. This cost, which can be determined from the overall ROR or weighted average cost of capital, should produce sufficient earnings and cash flow when applied to the respective company's rate base at book value to enable a company to maintain the financial integrity of its existing invested capital, maintain its creditworthiness, attract sufficient capital on competitive terms to continue to provide a source of funds for continued investment, and enable a company to continue to meet the needs of its customers.

These standards are effectively mandated by the landmark U.S. Supreme Court decisions Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944) ("Hope"). Meeting these requirements is necessary in order for a company to effectively meet the utility services requirements of its customers and provide an adequate and reasonable return to its investors, debt holders and equity holders, alike.

B. Resolved Issues and Immaterial Differences

Staff witness Ms. Phipps proposes to adjust the capital structure to remove the remaining Construction Work in Progress ("CWIP") accruing an allowance for funds used during construction. For the purposes of this docket, AIC does not object to the results of the proposed adjustment.

AIC and Staff agree there is no material difference between the average 2012 preferred stock balance of $59,158,692 that Staff recommends and AIC's proposed balance of $59,194,837.

Staff and AIC agree that AIC's average 2012 short-term debt balance equals $6,473,198.

Staff and AIC agree there is no material difference between the average 2012 long-term debt balance of $1,591,564,788 that Staff recommends and AIC's proposed balance of $1,591,759,083.

Staff and AIC agree that the average 2012 embedded cost of preferred stock equals 4.98%.

C. Common Equity Balance

1. AIC Position

AIC states that when Ameren acquired AmerenIP, generally accepted accounting principles ("GAAP") as then in effect required Ameren to "push down" certain items to AmerenIP's books. So that a mere change in control did not change Illinois Power's balance sheet for ratemaking purposes, the Commission required, as a condition of approving the change in control, that those "push down" effects be reversed for ratemaking purposes in Docket No. 04-0294. AIC says the Commission required that rates be set as if the accounting "push down" had never occurred.

AIC indicates that it and Staff disagree as to the proper adjustments required to effectuate the Commission's requirement in Docket No. 04-0294. AIC believes that it proposes to remove all effects of the accounting entries related to purchase accounting consistent with the Commission's Final Order in Docket No. 04-0294. AIC says Staff proposes only to remove the entire goodwill balance, while leaving other purchase accounting entries in place that are directly related to the AmerenIP acquisition. In AIC's view, the heart of the issue pertains to the proper means of excluding the purchase accounting on AmerenIP's books.

AIC argues that contrary to Staff's position, all effects of purchase accounting should be adjusted out of the capital structure, including eliminating the effects of amortizations created by virtue of fair market value purchase accounting entries made at the time Ameren acquired AmerenIP. AIC insists it is unfair to cherry-pick adjustments going one way and ignore off-setting adjustments going the other way, as Staff has done with regard to the purchase accounting effects on AIC's capital structure.

AIC maintains that when Ameren acquired AmerenIP, financial accounting standards required that Ameren "push-down" its investment to the newly acquired subsidiary's books and re-examine the book value of assets and liabilities and reset those book values based upon the fair market value of the acquired assets, including the effect of the premium that Ameren paid, which was reflected as goodwill. AIC says the resulting accounting entries are referred to generally as "push-down accounting" or "purchase accounting," one significant effect of which was to alter AmerenIP's capital structure by changing the balance of common equity. AIC states that in Docket No. 04-0294, Staff recommended, and Ameren and the Commission agreed, that the effects of the purchase accounting should be reversed for ratemaking purposes. According to AIC, this was necessary and appropriate because the Commission sets rates based upon a rate base that is valued at book. AIC claims it would not be appropriate to change rates to reflect a change in the cost of service that occurred simply because AmerenIP had a new corporate owner. AIC asserts that reversing all the push down adjustments means the push down accounting under GAAP has a neutral effect on the cost of service.

AIC claims that since Docket No. 04-0294, the Commission has followed through and consistently followed the principle of neutrality reflected in its approval conditions in Docket No. 04-0294. AIC says that thereafter, the Commission approved capital structures in the last three AIC rate cases that reflected reversal of all push down accounting adjustments.

In AIC's view, what Staff wants to do now is reverse just one of the push down adjustments and leave the others in place, meaning that push down accounting would not have a neutral effect on cost of service, as was intended, but in fact would serve to lower the cost of service. AIC insists there is no justification for this result. AIC contends that the items that Staff wants to leave in place came about only because Ameren paid the premium that produced the goodwill. AIC maintains that Staff wants to exclude the goodwill, but leave the off-setting effects in place.

AIC asserts that Staff's position in this proceeding is inconsistent with the Order in Docket No. 04-0294, sound ratemaking principles, and is without evidentiary support. AIC argues that in this case, Staff appears to at times accept the concept of reversing purchase accounting entries, but at other times disagrees that purchase accounting adjustments should be made. According to AIC, Ms. Phipps recognizes that multiple accounting entries are made as related to "purchase accounting" but also disagrees with reversing any entry other than the cumulative total of goodwill as recorded in Uniform System of Accounts ("USOA") No. 114 ("Account 114"). AIC contends there are accounting entries intertwined with the balance relied upon by Ms. Phipps as a result of purchase accounting.

AIC also claims that Ms. Phipps, who is not a certified public accountant, was not familiar with either the financial accounting standard referenced in Docket No. 04-0294, or the account entries filed by AmerenIP in compliance with the Final Order issued in that docket. AIC also claims that Ms. Phipps recommends accounting treatment at odds with the manner in which AIC is directed to comply with its annual reporting requirements ("Form 21 ILCC").

AIC indicates that Staff also relies upon the direction in the Final Order in Docket No. 04-0294, indicating the impact of the purchase accounting should be collapsed into Account 114 for regulatory purposes. AIC alleges that Account 114 contains the $411 million goodwill balance that Ms. Phipps removes. AIC complains that she does not "collapse" the other purchase accounting entries into that account balance, as AIC claims it does in its Form 21 ILCC, or otherwise net them against goodwill. In AIC's view, Staff misses the point that AIC is collapsing all adjustments into that account entry for regulatory purposes by netting all purchase accounting adjustments against that entry and reporting the same to the Commission annually. AIC contends this is precisely how it complies with the Final Order issued in Docket No. 04-0294. AIC insists reduction of goodwill is a single collapsed adjustment made in lieu of adjusting other accounts in piecemeal fashion to fully reverse the purchase accounting entries. AIC argues that this treatment is consistent with what the Commission approved in Docket No. 04-0294 with regard to both ratemaking and Form 21 ILCC reporting.

AIC states that subsequent to the Final Order in Docket No. 04-0294, Financial Accounting Standards changed as of 2006 pertaining to how certain purchase account entries are made, and the recordation process for those entries had to be adjusted, specifically regarding Account 219. AIC asserts that it cannot be said that AIC's present accounting entries justify a departure from the Commission's decision in Docket No. 04-0294.

AIC believes Staff does not justify why the Commission should asymmetrically reverse the goodwill entry, yet leave other purchase accounting entries in place for the purpose of developing a capital structure. AIC maintains that proper treatment is accomplished by reversing all of the purchase accounting entries to accounts resulting from the AmerenIP acquisition as they impact test year accounts. AIC says it has done so for the past three rate cases by netting the purchase accounting amortized entries against the goodwill asset.

It is AIC's position that the Commission should affirm its regulatory treatment of the purchase accounting related to the AmerenIP acquisition in this case and accept AIC's proposed accounting thereof for the purpose of establishing AIC's capital structure.

In its Reply Brief, AIC alleges that the majority of Staff's arguments concerning goodwill and purchase accounting consists of entirely novel assertions that were simply not presented in the direct or rebuttal testimony of Ms. Phipps, the sole Staff witness addressing the issue. AIC states that the first page of the section does paraphrase the testimony of Ms. Phipps, but claims the remainder of the argument is the presentation of a new theory. According to AIC, Staff now claims it could not "verify" the accounting, and this claim is somehow supported by a series of obscure criticisms concerning the nature of dividends and when they should be made.

AIC asserts that because Staff waited to raise these issues in its Initial Brief, AIC has been deprived of any meaningful opportunity to respond. AIC alleges that Staff essentially presents new expert analysis in its Initial Brief. AIC says it cannot now enlist an accountant to review and rebut the information on the record; it cannot now propound discovery to understand the basis for the generalized criticisms, and cannot conduct any cross examination of the expert whose work product is presented on pages 51-52 of Staff's Initial Brief. AIC argues that from a legal standpoint the tactic unduly prejudices AIC; sustaining an approximately $2 million dollar revenue requirement adjustment based upon evidence the AIC has not been given an opportunity to rebut cannot be achieved without violating AIC's due process rights.

AIC contends that while Staff does provide some citations to the record, specifically the transcript, a quick review reveals that the admissions attributed to Mr. Stafford either did not occur or were highly conditional and without certainty. Of concern to AIC, Staff alleges ". . . the common equity balance that AIC presents to its investors excludes goodwill instead of purchase accounting adjustments," and Staff follows with a citation to Mr. Stafford's cross examination. AIC Reply Brief at 29, citing Staff Initial Brief at 51. AIC asserts that the attribution does not accurately depict the subject matter of the questioning, which made no mention of a concept of goodwill "instead" of purchase accounting. AIC believes this is important because Mr. Stafford agrees that goodwill should be removed from the common equity balance, but only to the extent the removal is net of other purchase accounting adjustments. AIC also asserts that, Mr. Stafford did not even make an admission as Staff's citation would infer. AIC states that when asked if AIC excluded "goodwill" from presentations to investors, referring to a report, Mr. Stafford indicated that he ". . . did not know with certainty whether it would or wouldn't." (d. at 29-30, citing Tr. at 235. AIC alleges that Mr.

Stafford did accept a representation by counsel "subject to check," but the purpose of such acceptance is not an unequivocal admission, as Staff's citation would suggest. AIC claims a "subject to check" question is customarily asked for the purpose of laying some context for further questioning in order to move the hearing along, not some legal trickery by which a witness is forced to admit something to which they have questionable familiarity or recollection. AIC claims Staff has abused the custom in this instance.

AIC also states that Mr. Stafford indicated he could not authenticate the documents counsel was asking him about. With regard to Staff Cross Ex. No. 9, AIC says Mr. Stafford said he did not remember seeing the exhibit. AIC adds that he later corrected that he did recall being asked to review a single slide in the broader presentation but counsel did not ask him about that slide. With regard to Staff Cross Ex. 10, counsel asked Mr. Stafford about a document held out to be a single undated page taken out of what he was told was a 2007 rate case 285 schedule. AIC indicates it is not to suggesting the document was a fake, but says Mr. Stafford could not confirm its authenticity. AIC states that Staff did not seek admission of its Cross Exhibits 9 and 10, and they are not part of the record. AIC complains that Staff cites specific values from those exhibits in its Initial Brief.

According to AIC, the fact is that Staff fails to explain why it should depart from the accounting approved in Docket No. 04-0294, AIC's annual reporting in Form 21 ILCC, and the capital structure approved in the past three rate cases. AIC maintains that Staff does not "collapse" other purchase accounting adjustments against goodwill or otherwise reverse the totality of the purchase accounting that resulted from the acquisition of AmerenIP.

2. Staff Position

AIC's average 2012 common equity balance excludes approximately $344 million of purchase accounting adjustments reflected in Account 114 as of September 30, 2010. Staff avers AIC'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 AIC's purchase accounting adjustment balance to avoid including in rates any purchase accounting adjustments that are not appropriate for ratemaking purposes.

Staff recommends that the Commission reject AIC's proposed purchase accounting adjustments because they could not be verified. Staff asserts that those purchase accounting adjustments reflect unrelated amortization of Account 219, Accumulated Other Comprehensive Income. Staff also argues that push down accounting entries must be finalized within one year of the closing date of reorganization. Staff says that once finalized, purchase accounting adjustments should decrease ratably until the end of the applicable amortization period. Staff complains that AIC expects the purchase accounting adjustment to increase from 2010 to 2011, then decrease from 2011 to 2012. In contrast, Staff says AIC expects its goodwill balance will remain constant in 2011 and 2012. Staff also claims that the common equity balance that AIC presents to its investors excludes goodwill instead of purchase accounting adjustments.

Staff asserts that without explanation, AIC dropped $63 million in income-related purchase accounting adjustments from its current rate case. Staff claims that in the 2007 AmerenIP rate cases, AIC made two purchase accounting-related adjustments to AmerenIP'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." Staff Initial Brief at 21, citing Tr. at 238-242. Staff finds this troubling given the difference between AIC's $344 million purchase accounting adjustment and $411 million goodwill balance equals approximately $63 million, suggesting to Staff that a similar retained earnings adjustment in the instant case would have resulted in purchase accounting adjustments that approximate AIC's goodwill balance.

According to Staff, AIC's explanation is that the $63 million would have been an adjustment made after the AmerenIP 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 and that the $63 million was specifically related to retained earnings from income generated from push down accounting or purchase accounting. Staff says AIC also contends that until such time as the retained earnings have been fully paid out in common dividends, the Company will make that adjustment.

Staff states that while purchase accounting is required for financial reporting purposes, and AIC must reverse the effects of purchase accounting for regulatory purposes, dividends do not represent a reversal of purchase accounting adjustments to net income, as AIC claims. Staff argues that instead, companies declare dividends out of earnings as a whole, rather than a particular type of earnings; the USOA defines retained earnings as the accumulated net income of the utility less distribution to stockholders and transfers to other capital accounts. Staff also contends that the USOA provides no instruction for tracing dividends to a particular source of utility income. According to Staff, AIC admits that it is almost impossible to pinpoint exactly how cash is used. Staff also says that in Docket No. 04-0294, the Commission lifted pre-existing restrictions on AmerenIP's common dividend payments. Given AmerenIP was not prohibited from paying dividends following the acquisition by Ameren, Staff argues it is not clear why any "unpaid" common dividend would still remain when AmerenIP filed its 2007 rate case almost three years following its acquisition by Ameren. Staff finds AIC's explanation for its exclusion of the 2007 rate case adjustment to retained earnings from the current rate cases should be insufficient because it is contrary to the Commission's rules and its Order in Docket No. 04-0294 allowing AmerenIP to recommence dividend payments.

Staff maintains that it cannot verify AIC's proposed purchase accounting adjustments, which may result in an overstatement of the common equity balance for ratemaking purposes. Staff asserts that Ms. Phipps' adjustment would avoid including in rates any purchase accounting adjustments that are not appropriate for ratemaking purposes. Staff believes the Commission should adopt Staff's proposed common equity balance for AIC, which excludes $411 million goodwill.

In its Reply Brief, Staff claims that AIC mischaracterizes Staff's position when it argues that Staff's proposal contradicts the Commission's directive in Docket No. 04-0294. Although Staff does not oppose the accounting treatment authorized in Docket No. 04-0294, Staff recommends against adopting AIC's proposed purchase accounting adjustments for setting rates in this proceeding because AIC's proposed purchase accounting adjustments are not verifiable. Specifically, Staff witness Phipps argued that to the extent purchase accounting adjustments affect Account 219, the balance should decrease ratably until the end of the applicable amortization period. Moreover, Staff maintains that it identified a $63 million retained earnings adjustment that appeared in AIC's 2007 rate case, but which does not appear in the instant case.

It is Staff's position that contrary to AIC's assertion, AIC's proposed adjustments in the instant case are not consistent with AIC's proposed adjustments in the last three rate cases because the instant case does not include a $63 million adjustment to retained earnings that AIC made in the 2007 rate case. According to Staff, absent the adjustment to retained earnings, AIC could be inflating its common equity balance by approximately $63 million, which would contradict the Commission's Order in Docket No. 04-0294, which AIC argues required reversing purchase accounting adjustments in order to ensure Ameren's acquisition of AmerenIP would have a neutral effect on the cost of service.

3. Commission Conclusion

Staff recommends removing from the common equity balance the balance of goodwill on AIC's books. AIC argues that Staff's proposal reduces the common equity balance by too much because a portion of the goodwill balance on its books is offset by purchase accounting transactions.

As an initial matter, the Commission observes that this issue involves rather technical accounting issues that are neither easily explained nor understood. While the Commission does not fault either AIC or Staff for their efforts on a difficult issue, it seems to the Commission that thorough communication could have resulted in a mutual understanding between the parties. Unfortunately, this did not happen and the Commission is forced to resolve this difficult issue.

In direct testimony, Ms. Phipps proposed removing $411 million of goodwill from AIC's common equity balance. She notes that AIC proposed to use the September 30, 2009, balance of the purchase accounting adjustments reflected in Account 114–Plant Acquisition Adjustments. She asserts that that balance reflects bookkeeping entries to Account 114 that do not affect AIC's common equity balance.

In rebuttal testimony, Mr. Stafford states that the netting of purchase accounting adjustments against Account 114 goodwill is required to be reported annually on AIC's Form 21 ILCC as a difference between AIC's Form 1 and Form 21 ILCC balance sheets. He claims that AIC's purchase accounting adjustments are verified by an accounting officer in the filing of Form 21 ILCC, and verified separately by an accounting officer at the time of rate case filings. Mr. Stafford also asserts that the purchase accounting adjustments are intertwined with goodwill. The Commission also notes that in Docket No. 04-0294, the Commission found that:

> The Commission also adopts the recommendation of Staff witness Ms. Pearce that the impact of push down accounting should be collapsed into account 114, plant acquisition adjustments, for all Illinois regulatory purposes, such as reporting in Form 21 ILCC. Order at 33-34.

In rebuttal testimony, Ms. Phipps states that goodwill is a direct result of purchase accounting. She does not, however, directly respond to Mr. Stafford's arguments about Account 114 nor attempt to refute his arguments about the intertwining of purchase accounting and goodwill.

As previously discussed, the Commission understands purchase accounting to be technical and complex. It appears to the Commission that while easy to understand, Staff's recommendation on this issue is overly simplistic. The Commission concludes that the record supports AIC's position that purchase accounting and goodwill are intertwined. It is clear to the Commission that Staff's recommendation does not reflect this fact. The record supports AIC's position that the common equity balance should be reduced by $350,833,351. This adjustment reflects a netting of accounting adjustments against the goodwill balance which is supported by the record of this proceeding. Substituting this value into Staff Ex. 24.0, Schedule 24.03 in place of the value used by Staff, $411,000,000, produces an average common equity balance of $1,889,251,000, which the Commission believes should be used for purposes of setting rates in this proceeding.

D. Cost of Short-Term Debt

1. AIC Position

AIC argues that Staff's adjustment to the 2012 cost of short-term debt, as well a 2012 planned long-term debt issuance, is premised upon the use of historically low interest rates present immediately preceding its direct testimony. AIC says that in contrast, Mr. Martin utilized Blue Chip Financial Forecasts dated December 1, 2010, to develop a forecast of interest rates applicable. AIC indicates that Ms. Phipps opposes AIC's position citing her belief that current interest rates are appropriate for use in 2012. AIC believes that in a future test year, it is appropriate for a utility to use recognized financial industry forecasts to test year interest rates as Mr. Martin did in this docket. AIC recommends that the Commission approve Mr. Martin's proposal as set forth in his direct testimony.

2. Staff Position

Staff states that AIC'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 London Interbank Offered Rate ("LIBOR"), plus a 2.05% margin that is based on AIC’s senior unsecured credit ratings of Baa3/BBB- from Moody’s Investors Services ("Moody's") and Standard and Poors ("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 at 8-9.

Staff finds AIC's proposed short-term debt rate problematic for two reasons. Staff complains that AIC used the projected 3-month LIBOR rate to estimate the cost of 30-day bank loans, which Staff believes will overstate AIC's actual cost of short-term debt because interest rates typically rise as the time horizon for the investment lengthens. Second, Staff says AIC’s proposed short-term debt rate is based on a forecasted interest rate instead of a current, observable interest rate. Staff indicates that AIC argues that it is reasonable to rely on interest rate forecasts, which are based on expert analysis, for forward test year purposes. In Staff's view, accurately forecasting interest rates is problematic. Staff also asserts that the accuracy of a forecast diminishes as the time horizon lengthens. According to Staff, 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 recommends that the Commission 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.

3. Commission Conclusion

There are two contested issues affecting the cost of short-term debt, the cost rate for bank loans and the treatment of credit facility commitment fees. The Commission understands that Mr. Martin and Ms. Phipps agree that AIC's cost for short-term bank loans is based on the sum of the then current 30-day LIBOR rate and a margin of 2.05%. The basis for AIC's proxy for the LIBOR rate in the formula is the projected three-month LIBOR rate. In contrast, Staff recommends using the current one-month LIBOR rate.

The question is whether to use AIC's projected three-month LIBOR rate or Staff's current one-month LIBOR rate in estimating the cost rate for bank loans. On the one hand, AIC complains that Staff's proposal relies on historically low interest rates. On the other hand, Staff argues that forecasting future interest rates is problematic. Staff also argues that because interest rates typically rise as the time horizon for the investment lengthens, AIC's three-month method overstates the interest rate.

It is impossible to know what the LIBOR rate will be when rates established in this proceeding will be in affect. The Commission concludes that by basing its estimate of the 30-day LIBOR rate on projected three-month LIBOR rates, AIC has overstated the interest rate. Of the two proposals offered, the Commission finds Staff's to be better and it is hereby adopted for purposes of this proceeding.

E. Credit Facility Commitment Fees

1. AIC Position

AIC indicates that it requires liquidity provided by short-term debt in order to ensure a source of cash is available if needed to support operations. In order to establish the facilities and lines of credit with participating banks, AIC says it is required to pay an upfront fee. For the purposes of ratemaking, AIC says the fee is expressed as a basis point equivalent value, and then blended within the overall cost of capital in proper proportion to the approved capital structure. AIC indicates that it and Staff disagree on the amount of fees recoverable in rates, while no other parties have taken a position on the issue. AIC says the disagreement stems from Staff witness Ms. Phipps's proposal to adjust credit facility commitment fees based upon what it views as a misapplication of Section 9-230 of the Act. Staff recommends recovery only to the extent of fees equivalent to 25 basis points. AIC proposes recovery of the actual fees paid equal to 66.5 basis points. AIC claims Ms. Phipps has not adequately supported the reasonableness of the resulting fees she proposes to be recoverable in rates. AIC believes Staff's adjustment should not be approved and, accordingly, a full 10 basis points should be added to overall weighted average cost of capital.

In support of its position, AIC invokes an argument that, as a matter of constitutional law, utilities are entitled to ask for a fair return upon the value it employs in providing public service. AIC also invokes the argument that Illinois utilities are entitled, as a matter of state law, to fully recover the costs of providing distribution service. AIC repeats its belief that Staff's adjustment is premised upon an errant application of Section 9-230 of the Act.

AIC thinks the statute is clear; for the purpose of setting rates, the Commission should not allow any incremental risk or cost of capital to be passed onto customers to the extent such risk or cost is the result of affiliation with non-regulated or unregulated affiliate businesses. AIC suggests the question for the Commission is two-fold: has AIC established a record to support its entitlement to a full recovery of credit facility fees; and does a reasonable application of Section 9-230 warrant an adjustment in this case?

AIC believes it provided substantial evidence in support of the bank facility fees it paid and the allocable portion thereof that it requests recovery of in this proceeding. AIC says Mr. Martin developed a facility for AIC separate and distinct from the affiliate facilities developed for AmerenUE and AIC's unregulated generation affiliates. AIC claims it provided proof of the three distinct facilities by providing the three distinct Arrangers Fee Letters attached to Mr. Martin's rebuttal testimony. AIC says it also provided a copy of the invoice showing that each facility was billed as a separate itemized amount.

AIC argues that Mr. Martin developed a facility that included lower cost modest commitments as well as commitments from larger, more stable lenders capable of making more meaningful commitments, and that he provided a breakdown demonstrating the diversity of commitments made to AIC by participating lenders and the associated fees. AIC says it also provided an exhibit showing comparable fees paid during 2010 by other utilities with similar credit ratings. AIC asserts that both the Peoples as well as Commonwealth Edison Company ("ComEd") paid fees comparable to AIC. AIC says it paid a fee equivalent of 66.5 basis points, whereas ComEd paid 60.5 and Peoples, together with its affiliates, paid an approximate range of 65-70 basis points. AIC also says it voluntarily reduced the fees for the portion of the total credit commitment available under the facility that could be called upon by Ameren.

AIC believes Staff misapplies Section 9-230 and proposes an "unsustainable" adjustment in three important ways. AIC says that first, Staff inappropriately suggests that the facilities be pooled into a hypothetical single facility and further assumes escalating fees as a result of a hypothesized single line of credit. Second, AIC says Staff improperly includes in its combined analysis the fees associated with a regulated utility, AmerenUE. AIC contends that affiliations with regulated utilities by definition cannot give rise to a Section 9-230 adjustment. Finally, AIC claims Staff failed to establish in the record any basis in fact or expert opinion that AIC could realistically obtain a reliable credit facility for a fee as low as 25 basis points.

Staff argues that the Commission should consider all three Ameren facilities, including the facilities arranged for AmerenUE, AIC's generating affiliate, and AIC, under one single progressive fee structure, and quotes from a response to a Staff data request response in support of this theory. AIC contends that Staff takes the explanation provided in Mr. Martin's response entirely out of context, failing to note that Staff specifically requested a comparison of affiliate bank facilities. AIC says Ms. Phipps attached the quoted data request responses and another related request to her testimony as Attachment 1 and 2. According to AIC, those requests asked Mr. Martin to provide a comparison of the three separate facilities. AIC says it was Ms. Phipps that requested the information be provided on a unified basis.

AIC maintains that the facilities were separate and distinct from one other, and AIC has only requested recovery of the specific fees associated with the AIC facility according to the invoice received. AIC believes that if anything is demonstrable by virtue of the analysis Mr. Martin provided in the responses contained in Attachment 1 and 2, it is that no preferential treatment was given or subsidy afforded to any AIC affiliate in the development of the three separate credit facilities. AIC argues that the data request responses actually support a finding that there was no adverse impact on AIC's costs that would be excluded from rates under Section 9-230.

According to AIC, Staff did not offer any opinion or provide any market-based analysis in support of the availability of a facility of comparable composition and quality to AIC for the fee equivalent to the 25 basis points recommended by Ms. Phipps. AIC says Mr. Martin could not line up key lenders for such a fee. It is AIC's position that it would be impossible to procure a stable, reliable facility of the size required by AIC by offering all lenders a commitment fee of 25 basis points. AIC says Ms. Phipps admitted she had no opinion to offer as to the availability of an $800 Million dollar facility to AIC for 25 basis points, and further admitted that she did no market research to test the validity of such a fee.

In its Reply Brief, AIC contends that Staff misses the point of the matter, Ameren negotiated three separate facilities for each business line, fully segregating the respective aggregate credit commitments to Ameren Illinois, AmerenUE, and Ameren Energy Generating Company ("Genco"). AIC says the basis for Staff's aggregated fee theory derives largely from excerpts taken from data requests Staff sent to AIC specifically asking for a side by side comparison of the three facilities. AIC also asserts that Staff indirectly takes aim at the manner in which Ameren negotiated the facilities for each business line, essentially arguing that the contemporaneous approach to setting up the three facilities somehow caused AIC and its affiliates to pay more overall despite having separate facilities, thus inflating the share attributable to AIC. AIC believes Staff has not explained or even suggested how it would be possible for the AIC to reduce its facility fees through some alternative negotiation process, whereby somehow AIC could convince banks to accept a lower fee for the same amount of credit commitment. AIC also believes it is incorrect when Staff alleges AIC holds out that the facilities were negotiated at different times. AIC claims Mr. Martin has been transparent about how the facilities were syndicated.

In AIC's view, this is a classic straw man argument where Staff chooses to continue to interpret "separately negotiated" in a cynical manner in order to make it appear that AIC somehow is trying to obscure what is truly an in-broad-daylight approach to credit facility syndication. AIC says Mr. Martin used the word "negotiated" trying to explain the issuance of three separate lending facilities to different legal entities, in the same vein as someone saying that they negotiated three separate checks, meaning the person wrote three checks as opposed to one, not that they sat a table and entered into adverse negotiations on three different occasions. AIC claims the notion of a person to person negotiation is a misrepresentation of the nature of the syndication process, which AIC asserts is more of a multi-bank bidding process.

AIC contends that contrary to Staff's interpretation, Section 9-230 is not a discrete alternative to the application of reason or reasonableness. AIC says it has not asked the Commission to ignore Section 9-230 by virtue of some substitute reasonableness standard. AIC suggests the Commission may review the positions of the parties for their reasonableness in application of the facts to the legal principles at issue, Section 9-230 applicability notwithstanding.

AIC asserts that in the case Staff relies upon, Illinois Bell Telephone Co. v. Illinois Commerce Comm'n, the appellate court was simply indicating the Commission erred in addressing "reasonableness" generally for the basis of its decision to reject CUB's proposed Section 9-230 adjustment in the Order under review. AIC Reply Brief at 33-34, citing Staff Initial Brief at 55, 283 Ill. App. 3d 188, 207 (2nd Dist. 1996). AIC says the appellate court correctly concluded that reasonableness alone is not sufficient to sustain a ruling upon a Section 9-230 determination and the Commission must specifically address whether incremental risk or additional costs were caused due to an unregulated affiliate. AIC states that the complete holding of the appellate court goes on to identify the case establishing the appropriate standard to which the Commission is held. Id. citing Central Illinois Public Service Co. vs. Illinois Commerce Comm'n, 243 Ill.App.3d 421, 443 (4th Dist. 1993). According to AIC, in Central Illinois, the court affirmed the Commission when it made an express finding the utility was unaffected by its unregulated parent. AIC believes it is pertinent to this case that Central Illinois made it clear in upholding the Commission's decision argument that ". . . [t]he credibility of expert witnesses and the weight to be given to their testimony are matters for the Commission to decide as finder of fact." (d., citing 243 Ill.App.3d at 443.

According to AIC, the problem with the legal sustainability of Staff's adjustment in this case is that it fails to establish the condition Section 9-230 specifically prohibits. AIC insists there must be some showing or measure of incremental or additional risk or cost of capital attributable to the affiliate's influence on the cost of capital. To demonstrate incremental or additional cost, AIC claims it is necessary to establish some kind of baseline that would provide a reasonable basis for what would have been paid in fees without the alleged influence of the unregulated affiliate or affiliates. AIC asserts that Staff provided no market analysis to support what AIC would have paid, nor did Staff offer any opinion that the AIC could have obtained a comparably reliable and stable facility for a mere 25 basis points or otherwise attempt to defend this number.

AIC contends that Staff has still not explained, in testimony or its Initial Brief, why it is appropriate to pool and inequitably divide AmerenUE and AIC costs as part of its analysis. AIC says it does not dispute that it cannot recover AmerenUE costs – most certainly it cannot, but AIC believes a proper interpretation of Section 9-230 would hold that the law pertains to unregulated, non-utility affiliates (i.e. Merchant generation, marketing affiliates, and the like). In AIC's view, if Staff feels a jurisdictional cost allocation issue is present, it is free to raise it, but insists Section 9-230 is the wrong statute to rely upon. AIC believes that to support Staff's analysis, the statute would have used language to the effect of ". . . affiliates other than a public utility," as opposed to the very specific descriptors "non-utility" and "unregulated." AIC also claims it does not appear from Staff's Initial Brief that Staff is directly arguing AIC paid AmerenUE costs, but rather total costs were inflated due to the manner of negotiation.

Regardless of the legal basis for the adjustment, AIC insists the issue with regard to AmerenUE is also one of fairness. In AIC's view if the Commission pools two separate lines of credit into one and assigns the smallest, least cost commitments to AIC, Ameren certainly cannot expect to proportionally recover the larger higher cost commitments from its Missouri customers. AIC believes it should be permitted to recover the costs it incurs on behalf of a facility entered into to support AIC operations. AIC thinks the better solution here is to leave the commitments separate and associated with their own fee, as AIC proposes to do in this case.

2. Staff Position

Staff states that 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 Genco credit facility. Ms. Phipps calculated one-time arrangement and upfront fees for AIC 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 says the contested issue regarding bank commitment fees relates to the amount of upfront fees. Staff notes that Section 9-230 of the Act prohibits including in a utility's allowed ROR any increased cost of capital which is the direct or indirect result of the public utility's affiliation with unregulated or non-utility companies. Staff says bank commitment fees vary from 0.25% to 0.875% of the amount of each lender's aggregated commitments to the three credit facilities. Staff adds that AIC's response to 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." Staff claims the highest commitment by a single lender to the Illinois Facility was $47.62 million. Staff claims 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). Staff also contends that Ameren's ability to borrow up to $300 million under the Illinois Facility effectively reduces the AIC sub-limit to $500 million (or 62.5% of the $800 million facility). Ms. Phipps calculated $1,250,000 of upfront fees she believes is recoverable for ratemaking purposes pursuant to Section 9-230 of the Act.

AIC alleges that Ms. Phipps misinterpreted data it provided regarding upfront fees. Further, AIC alleges that it separately negotiated the upfront fees for the Illinois Facility. Staff believes the facts show otherwise. According to Staff, the invoice setting forth the closing fees covers all three credit facilities. Staff also asserts that the Illinois, Missouri, and Genco upfront fees are identical percentages of the total commitment to those facilities (i.e., 0.665%). Staff claims that excepting the names of the companies listed, the Arrangers Fee Letters are identical for the three facilities. Staff also contends that 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.

Next Staff asserts that since the Commitment Fee Rates are all multiples of 0.5 basis points and each bank commitment is a multiple of $5 million, each bank received a commitment fee that is a multiple of $250 (i.e., 0.005% x $5 million). Staff says, nonetheless, the upfront fees to the three facilities are all calculated to the nearest penny (i.e., $3,325,892.86 to the Genco credit facility and $5,321,428.57 to both Illinois and Missouri credit facilities). Staff argues that 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, Staff insists some variation in these fee amounts and individual bank commitment amounts per total commitment should exist, but there is none.

Staff notes that AIC claims that its 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. Staff argues that to the contrary, under the terms of the Illinois facility, the upfront fee rates increase as commitment amounts increase. Staff asserts that 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. Staff also believes 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 says AIC 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. Staff believes AIC's argument should be disregarded on two levels. On the factual level, Staff claims the argument implies the data for credit facilities provided in Ameren Ex. 24.5 are similar to the Illinois facility. Staff asserts that 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). Staff also contends that AIC's argument misses the legal issue. Staff insists the adjustment to the upfront fees is not a matter of reasonableness or prudence. Staff believes 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. Staff maintains that the fee rate AIC pays is a direct function of its affiliation with non-utility and unregulated companies. Staff says the greater the commitment to the Missouri and Genco facilities, the higher upfront fee rate AIC pays.

According to Staff, Illinois courts have specifically addressed this issue regarding the interpretation of Section 9-230 of the Act. Staff believes all discretion for the Commission has been removed. Staff insists 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 borne by the utility's ratepayers; the legislature has determined that any increase whatsoever must be excluded from the ROR determination. Staff believes it is impermissible for the Commission to substitute its reasonableness standard for the legislature's absolute standard. Staff says the Court determined it is not permissible for the Commission to substitute its reasonableness standard for the legislature's absolute standard. In Staff's view, AIC's arguments that the Illinois facility fees were reasonable and prudent is irrelevant to its recovery of these fees. Staff insists that 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 AIC seeks.

In its Reply Brief, Staff says AIC alleges further that Staff's proposal misapplies Section 9-230 of the Act. AIC argues that Staff: (1) assumes escalating fees as a result of a hypothesized single line of credit; (2) includes in its combined analysis the fees associated with a regulated utility, AmerenUE. AIC contends that affiliations with regulated utilities by definition cannot give rise to a Section 9-230 adjustment; and (3) Staff failed to establish any basis in fact or expert opinion that AIC could realistically obtain a reliable credit facility for the fee equivalent as low as 25 basis points.

Staff argues that the pooling of the three Ameren facilities (i.e., Illinois facility, Missouri facility and Genco facility) into a "single line of credit" was an actual occurrence, not a hypothetical one, at least from the standpoint of applying upfront fees to each bank's aggregate commitment to the three facilities. In contrast, Staff claims it calculated the upfront fee as if the Illinois facility had been negotiated separately and that the upfront fee rates had been applied to the actual bank commitments to the Illinois facility. Staff says AIC insists that its customers compensate it for the higher fee rate that was assessed against the aggregate bank commitments to the three facilities. According to Staff, the escalating upfront fee scale for credit facilities of Ameren and its subsidiaries is nothing new. Staff says it made the same adjustment in the last AIC rate case, which the Commission adopted, despite similar arguments by AIC regarding the reasonableness of the bank commitment fees. (Staff Reply Brief at 34, citing Docket Nos. 09-0306 et al. (Cons.), Order at 155)

AIC asserts that Staff improperly includes in its combined analysis the fees associated with a regulated utility (AmerenUE) and argues that affiliations with regulated utilities by definition cannot give rise to a Section 9-230 adjustment. Staff contends that to the contrary, Section 3-105(a) of the Act limits its definition of public utility to companies that operate within Illinois. In Staff's view, a Missouri utility is not a "public utility" under the Act, which means, for the purpose of applying Section 9-230 of the Act, AmerenUE is a non-utility affiliate of AIC.

Staff maintains that whether the fee is reasonable in comparison to the fees other companies pay to obtain a credit facility is irrelevant. Staff insists that Section 9-230 adjustments are not reasonableness adjustments. Nevertheless, Staff says AIC points to upfront fees for ComEd and Peoples to show the AIC fees are reasonable. Staff suggests that fee rates could have declined over the five to six months that elapsed between the February 2010 and March 2010 effective dates of the ComEd and Peoples facilities on the one hand and the August 2010 effective date of the AIC facility on the other. Staff also contends there is no evidence in the record regarding whether there are escalating upfront fees associated with the Peoples credit facility and whether the fee rates Peoples paid were assessed against bank commitments to Peoples' facility in isolation or against aggregate bank commitments to all three Integrys Energy facilities (i.e., Integrys Energy, Peoples and Wisconsin Public Service). Staff believes that in any event, the reasonableness of those fees is irrelevant because whether costs are reasonable is beyond the scope of Section 9-230 of the Act. That is, Staff maintains that Section 9-230 prohibits incremental costs resulting from non-utility affiliates, regardless of whether a "market-based analysis" suggests those costs are reasonable.

3. Commission Conclusion

With regard to the credit facility commitment fees, Ameren Ex. 24.3 shows that on July 29, 2010, three credit facilities were executed. The Illinois credit facility is an $800 million facility for AIC and Ameren. The Missouri credit facility is also an $800 million facility for AmerenUE (now AMC) and Ameren. What is known as the Genco facility is a $500 million facility that includes Genco and Ameren.

Staff contends that if the Illinois credit facility had been established on its own separate from the Missouri and Genco credit facilities, the fees would have been lower. AIC maintains that the facilities were separate and distinct from one other, and it has only requested recovery of the specific fees associated with the AIC facility according to the invoice received. AIC insists that Ameren Ex. 24.1 shows the actual and appropriate fees associated with the Illinois credit facility. Staff disagrees because AIC's response to a Staff data request, which is part of the record as Staff Ex. 24.0, Attachment 1, shows a fee schedule that differs from what is shown on Ameren Ex. 24.1. Specifically, Staff's exhibit indicates that banks that commit less than $75 million are to receive a 25 basis point commitment fee rate. Staff points out that Ameren Ex. 24.1 shows that no bank committed more that $75 million to the Illinois credit facility.

AIC argues, essentially, that Staff misinterpreted the information shown in Staff Ex. 24.0, Attachment 1, because it presented fee rates based upon the aggregate amount borrowed under the three credit facilities. The Commission believes that, at least to some extent, this undermines AIC's assertion that the Illinois credit facility was negotiated entirely independently from the other two credit facilities. In the Commission's view, this issue involves the question of whether the fee rate schedule shown on Ameren Ex. 24.1, page 1, would have been exactly the same if the Illinois credit facility had been negotiated totally independently from the other two credit facilities. While the Commission believes that it is possible, AIC has failed to adequately demonstrate that this is certain, or even likely. The Commission finds Staff's reliance on AIC's response to a data request to be reasonable and, therefore, adopts Staff's recommendation with respect to the calculation of the Illinois credit facility fees.

F. Cost of Long-Term Debt

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

1. AIC Position

With regard to the coupon rate for AIC's expected October 2012 bond issuance, AIC indicates that the same argument concerning the use of forecasted versus present interest rates controls the outcome of this contested issue.

In 2008, AmerenIP issued $400 million of debt with a coupon rate of 9.75%. AIC states that in its last rate case, the Commission approved Staff adjustments to the cost of capital associated with this debt issuance. In the present docket, AIC says Staff proposes a new adjustment to replace $50 million worth of the 9.75% debt issuance with debt having a hypothetical coupon rate equal to the overall weighted cost of capital. AIC cannot accept Staff's proposed adjustment to AmerenIP's debt issuance, claiming it is unfair and lacks empirical analysis or other support.

AIC believes Staff's position as advanced in this case is not legally tenable. AIC insists it is entitled to recovery of its prudently incurred costs in providing service. In determining whether a management decision was imprudent, AIC says the Commission has held that hindsight review is impermissible and a finding of imprudence cannot be sustained by substituting one person's judgment for that of another.

According to AIC, Mr. Martin had personal knowledge of the undertaking of the 2008 debt issuance, and testified that it was prudently undertaken based on careful consideration of relevant and observable facts and circumstances during a period of near global financial catastrophe. AIC says Ms. Phipps claims that the debt was issued in an amount more than it required, but stated that Staff was not alleging imprudence. AIC says she also clarified her adjustment was not based upon any Section 9-230 analysis. Referring to the collapse of Lehman Brothers, AIC says Ms. Phipps even acknowledged the validity of Mr. Martin's stated position that at the time of the issuance financial markets were distressed.

In AIC's view, Staff has failed to articulate any facts or expert analysis that would support its proposed adjustment pursuant to an applicable legal standard. AIC argues that if Staff alleges no imprudence in the actions of management in this case or other legally sustainable basis for a disallowance, then Staff is simply substituting its judgment for that of the AIC's management in hindsight fashion. AIC maintains a disallowance cannot be sustained upon such testimony.

AIC states that in its Initial Brief, Staff has quoted a specific portion of the most recent AIC rate case Order in favor of the adjustment proposed by Ms. Phipps in the present docket. According to AIC, the cited portion of the order essentially explains that the Commission agreed with Staff; $50 million out of a $400 million long-term debt issuance by AmerenIP for 9.75% should be excluded from Ameren IP's long-term debt given that AmerenCIPS was contemporaneously enjoying a loan for the same amount contributed in part by AmerenIP through the intercompany money pool. AIC states that the finding reflects a concern related to cross-subsidization among separate Illinois utility affiliates. AIC's questions why this section would be cited by Staff in the present docket, considering AIC now has a single unified capital structure. AIC contends that the cross-subsidy concern is no longer relevant. AIC asserts that the debt capital associated with the AmerenIP issuance is now embedded within a unified capital structure inclusive of all pre-existing long-term debt, including both AmerenCIPS and AmerenIP issued debt.

AIC says it respectfully disagreed with Staff's adjustment, fully realizing a similar adjustment was previously approved over its objections. AIC says the legal basis for the disallowance is unclear. AIC also indicate it does not understand Staff's “perverse result” argument. In AIC's view, the rationale almost reads to mean that the company is being penalized for some misdeed, which is not management imprudence. Hypothetically speaking, AIC suggests that if a utility somehow did elevate the debt level errantly in a manner that reduced equity relative to debt, the result would be a neutral or beneficial impact on the capital structure and weighted overall cost of capital from a ratepayer perspective. AIC believes that if such circumstance were in fact the case, then it would follow that no adjustment is warranted.

AIC notes that Staff proposes an adjustment to AIC's 2008 debt issuance by AmerenCILCO bearing a coupon rate of 8.875%. Staff believes that reducing the coupon rate is necessary in order to comply with Section 9-230 of the Act, alleging that AIC's cost of capital is higher due to AmerenCILCO's affiliation with Ameren Energy Resources Generating (“AERG”) in 2008. AIC indicates a similar adjustment was proposed by Staff in Docket Nos. 09-0306 et al. (Cons.) and was ultimately approved by the Commission in that docket. AIC says Staff proposes a similar adjustment in this proceeding, with Ms. Phipps revising her adjusted coupon rate higher to 6.76% from 6.24%.

AIC believes no adjustment is warranted and it fundamentally disagrees with the methodology used to support it. AIC claims new facts have emerged since the last rate case, casting doubt on Staff's methodology. AIC claims Staff's analysis, even as revised in this case, is deficient, and the cost of the debt should be valued at its issued coupon rate of 8.875%.

AIC contends that AERG did not give rise to increased risk, or additional interest cost paid by AmerenCILCO, due to its then existing affiliation with AERG, or parent holding company, CILCORP. AIC says that in Docket Nos. 09-0306 et al. (Cons.), Staff proposed a disallowance based upon a methodology designed to replicate how credit ratings agencies would have perceived AmerenCILCO as a stand alone utility. Ms. Phipps employs the same methodology in support of her adjustment in the present case. She continues to believe such an adjustment is warranted by relying upon a hypothetical Moody's analysis that would surmise had AmerenCILCO been a stand alone utility, it would have been the highest rated utility in the United States by Moody's.

AIC contends that the hypothetical conditions that Ms. Phipps attempted to model in support of a stand-alone analysis have come to fruition. AIC states that in 2010, AmerenCILCO divested itself of AERG after the Order was issued in Docket Nos. 09-0306 et al. (Cons.) and prior to the closing of the merger creating AIC. AIC also says Fitch Ratings ("Fitch") issued a report downgrading AmerenCILCO's credit rating on May 20, 2010, citing expressly the transfer of AERG from AmerenCILCO and the loss of the associated margins as rationale supporting the downgrade. AIC indicates that Fitch is a credit ratings agency and it is recognized by the financial industry alongside S&P and Moody's.

In AIC's view the fact that Fitch would explicitly cite the divestiture of AERG as a reason supporting a downgrade would bode contrary to Ms. Phipps underlying premise, and the specific comment by Fitch regarding the "loss of electric gross margins" reveals the primary fault with Ms. Phipps' analysis. AIC says Fitch recognized that AERG contributed to AmerenCILCO's credit quality rather than detracted from it, specifically by generating substantial cash flow. AIC asserts that Ms. Phipps' failure to consider the import of significant cash flows generated by AERG erroneously led her to believe AmerenCILCO would have been substantially better situated as a stand alone utility from a credit ratings standpoint. AIC claims her "asymmetrical" approach caused her to remove business risk without consideration of business return in her attempt to replicate credit rating analytics. AIC further asserts that her own testimony illustrates the magnitude of the AERG cash flows in comparison to regulated operations.

According to AIC, Ms. Phipps' failure to include the cash and net income contributions of AERG in her analysis is exacerbated by her improper use of rating metrics and methodological guidance. AIC says Ms. Phipps assigned a "strong" S&P business risk profile to AmerenCILCO; however, a "strong" business risk profile does not lead automatically to a BBB+ issuer rating as Ms. Phipps' analysis would tend to suggest. AIC claims that on average a utility would need to have a user profile of "excellent," which is higher than "strong," to receive a BBB+ issuer rating from S&P. AIC states that for her Moody's analysis, which led to the development of her "Implied" Moody's credit rating of A1, Ms. Phipps utilized a ratings guidance framework that did not even exist in 2008. According to AIC, she appears to have applied credit metrics in 2008 using a 2009 ratings model mixed with a previously established 2005 model. AIC claims the resulting analysis offered by Ms. Phipps in direct testimony was "staggering" because she proposed disallowing over 263.5 basis points of interest costs, leading to a proposed revenue requirement reduction totaling almost $3 million.

AIC states that while Ms. Phipps ultimately did revise her adjustment upward by approximately 50 basis points in response to the criticism made by Mr. Martin, Staff continues to rely upon the same hypothetical Moody's stand-alone analysis to support a substantial disallowance against AIC of almost 220 basis points. AIC says Ms. Phipps dismisses the Fitch report, reasoning that since many factors contributed to the Fitch downgrade, a citation to the transfer of AERG does not warrant reconsideration of her analysis.

AIC insists a plain reading of the Fitch report contained in Ameren Ex. 24.6 reveals that the AERG transfer was a significant consideration, if not a primary driver, of the agency's ratings downgrade. AIC also claims that the fact that Ms. Phipps would note that many factors contribute to the overall credit picture belies the foundation of the analysis she employs in support of her adjustment.

AIC believes Ms. Phipps took Moody's comments concerning the business risk imposed upon AmerenCILCO by AERG out of the context of a broader ratings report in developing her analysis. AIC says Ms. Phipps agrees that a rating agency would look at many factors when it develops ratings. According AIC, her own stand-alone analysis focuses on one predominant factor: relative business risk associated with AmerenCILCO's affiliation with AERG. AIC says while acknowledging the existence of several "ratings drivers," she focuses on several comments appearing in a Moody's ratings report from 2009, under the heading "detailed ratings considerations," and more specifically, under the sub-heading entitled "Environmental Capital Expenditures at AERG." AIC claims the purpose of this section of the report was to highlight specific risks associated with the merchant business, not to make any statement regarding whether the merchant business improved or weakened AmerenCILCO's overall creditworthiness.

AIC does not dispute that Moody's did comment on the relative business risk of the AERG merchant generating units in its report. AIC maintains that those considerations were made within the context of environmental capital expenditures, as the heading suggests. AIC asserts many other factors were presented in the report including the legislative activity associated with the Illinois electric rate freeze and limited financial flexibility due the expiration of a revolving credit facility, as well as more detailed considerations. AIC also says Ms. Phipps acknowledges that while Moody's did make recommendations in a section of its report entitled "What Could Change the Ratings Up," the particular section makes no mention of the divestiture or transfer of AERG. It seems to AIC that if Ms. Phipps' logic were valid, and a stand alone AmerenCILCO unaffiliated with AERG would have been the highest rated utility in the United States by Moody's, the ratings agency would have made at least passing mention of the possible transfer, divestiture, sale or other similar action in its section entitled "What Could Change the Ratings Up."

AIC argues that Ms. Phipps did what she held out to oppose, taking in isolation one consideration from the context of broader considerations in a ratings agency report. According to AIC, the most glaring consideration that Ms. Phipps did not include in her analysis are the cash and income contributions of AERG – contributions that were considered by ratings agencies evaluating credit worthiness of AmerenCILCO.

AIC states that in rebuttal, Ms. Phipps asserts that she did not rely solely upon the affiliation with AERG as the basis for her adjustment, but also the debt associated with AmerenCILCO's parent holding company CILCORP. AIC contends that her own table demonstrates that for the years 2007 and 2008, the "Net Income" from AERG greatly exceeded CILCORP's "Interest Expense." AIC says even net of CILCORP interest expense, AERG net income exceeded what her tables identifies as "Illinois Regulated Income." AIC adds that Ms. Phipps' table does contain AERG net income amounts for 2005 and 2006 that are less than the CILCORP debt expense for the same respective period. According to AIC, Ms. Phipps also agreed that both of those years were prior to the lifting of the Illinois rate freeze, and she further acknowledged that Moody's and other credit ratings agencies would have been aware of that fact. AIC does not dispute that a credit ratings agency would look favorably upon reduced debt of a utility or its holding company, but claims it is equally clear a credit ratings agency would also give consideration to the cash contributions of business lines. With regard to AmerenCILCO's 2008 debt issuance, AIC maintains that AERG earnings greatly exceeded debt expense in the relevant period immediately preceding issuance. AIC believes it is asymmetrical to consider debt without associated revenue. AIC contends that while Ms. Phipps appears to argue that CILCORP debt is some separate factor she considered in addition to AERG income and cash flows, the asymmetrical analysis remains; Ms. Phipps considered non-regulated risk and debt, while at the same time ignoring the offsetting impact of non-regulated earnings and cash flows.

In AIC's view, it is illogical and unfair to assume that had AmerenCILCO not been affiliated with AERG and CILCORP it would have been the highest rated utility in the United States, affording it the ability to obtain debt at a rate approximately 220 basis points below what was actually paid. AIC believes the record cannot support such an analysis, nor can it sustain the resulting adjustment. AIC recommends that the Commission establish a cost of long-term debt for AIC at a weighted average cost inclusive of AmerenCILCO's 2008 debt issuance at its issued coupon rate of 8.875%.

In its Reply Brief, AIC repeats that Staff developed a hypothetical credit rating in order to replicate how Staff believed a credit ratings agency would view AmerenCILCO as a stand alone utility in 2008. AIC alleges that Staff's hypotheses can now be tested because the stand alone condition actually occurred and, during that time, Fitch issued a credit rating for the utility. According to AIC, Staff's hypothetical analysis held out that if AmerenCILCO had no affiliation with its parent, CILCORP, or its unregulated generation affiliate, AERG, it could have enjoyed a vastly improved credit rating.

AIC says Staff argues that the Commission should ignore the Fitch report because it is a "subsequent event." According to AIC, Staff's hypothetical stand-alone rating itself was a subsequent event. AIC contends that the only contemporaneous events would have been the conditions that led to the issuance of the debt at its stated coupon rate.

AIC adds that Staff also asks the Commission to disregard the Fitch report by arguing that several factors led to the downgrade in addition to the AERG divestiture. AIC claims the divestiture was a significant consideration of Fitch if not a driver of the downgrade. AIC also says it never held out the Fitch Report as exculpatory evidence in and of itself, but believes the report highlights the serious flaws in Staff's analysis – particularly the failure to consider net income and cash flows generated by AERG.

Staff additionally argues that the consolidation of the three Ameren Illinois Utilities was a factor that contributed to the Fitch downgrade. AIC says Staff cites this despite the fact that Staff's adjustment is premised on a theory that the presence of AmerenCILCO's unregulated affiliate's business risk increased the cost of its debt issuance. AIC notes that neither AmerenIP nor AmerenCIPS had unregulated generation affiliates. AIC argues that if the absence of an unregulated affiliate company so dramatically improves credit quality, it is inexplicable that a planned merger with two truly stand-alone utilities would be a factor that would negatively impact AmerenCILCO's rating, particularly considering the divestiture of AmerenCILCO's unregulated affiliates had already occurred.

2. Staff Position

AIC expects to issue $150 million bonds during October 2012 to replace the $150 million bonds that matured in June 2011. 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. 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).

Staff believes 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. Staff states that while AIC argues that it is reasonable to rely on interest rate forecasts, which are based on expert analysis, for forward test year purposes, accurately forecasting interest rates is problematic, and the accuracy of a forecast diminishes as the time horizon lengthens. Staff notes this is the same argument it makes with regard to the cost of short-term debt.

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. Staff notes that 10-year U.S. Treasury bond yields have fallen since the date of Staff's analysis. Staff says that on September 6, 2011, the 10-year U.S. Treasury bond yield equaled 2.02%, which Staff claims 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. Staff also asserts that Blue Chip Financial Forecast, AIC's primary source for interest rate forecasts, has lowered its projections since the January 2011 publication that AIC relied upon for its proposed long-term debt rate. Staff states that 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.

According to Staff, the effect of the decrease in interest rates can be seen in a recent bond issuance by ComEd. Staff says that in August 2011, ComEd issued $350 million 10-year bonds with a 3.4% coupon rate. Staff claims that 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. Staff contends that even if interest rates are at historic lows, AIC's forecast would require a large increase over a very short period, which is not plausible.

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. Staff says this adjustment is based on the Order from Docket Nos. 09-0306 et al. (Cons.) in which the Commission concluded that AmerenIP issued $50 million more long-term debt than required for its utility operations during October 2008.

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, Staff Ex. 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 asserts 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 ROR on rate base due to a shift in the capital structure weights from lower cost debt to higher cost common equity. Staff recommends that the Commission adopt its 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. (Cons.).

In its Reply Brief, Staff contends that AIC errs when it states that Staff proposes a new adjustment to replace $50 million worth of the 9.75% debt issuance with debt having a hypothetical coupon rate equal to the overall weighted cost of capital. Staff asserts that it set the coupon rate for the remaining $50 million of AmerenIP's October 2008 bonds equals to the 7.39% embedded cost of long-term debt. Staff maintains that this adjustment is a disallowance because AIC issued more long-term debt than required for utility operations in October 2008. According to Staff, despite AIC's attempt to re-litigate this issue in the instant case, AIC has presented neither a single new fact nor argument that the Commission did not consider in AIC's previous rate case – a case in which the Commission deemed AmerenIP's issuance of $50 million more long-term bonds than required for utility operations as imprudent.

AIC alleges that Staff failed to articulate any facts or expert analysis that would support its proposed adjustment. In Staff's view, AIC's argument misses the point entirely. Staff insists that AIC ignores the fact that the Commission already decided this issue in AIC's prior rate case. Staff says the Commission Order in Docket Nos. 09-0306 et al. (Cons.), clearly set forth numerous facts surrounding AmerenIP's October 2008 debt issuance– including the bankruptcy filing by Lehman Brothers and distressed financial markets – and concluded AmerenIP issued $50 million more long-term debt than required for utility operations. Staff also asserts that it is AIC's burden, not Staff's, to articulate new facts and arguments that would merit a different decision on this issue in the instant proceeding. Staff believes AIC has provided no new evidence or argument in support of its position. Staff claims such facts reveal the falsity of AIC's allegation that Staff's adjustment substitutes its judgment for that of the AIC management in hindsight fashion.

Staff asserts that AmerenCILCO's affiliation with both CILCORP and AERG adversely affected AmerenCILCO's cost of capital in December 2008 based on rating agencies' reports that indicated AmerenCILCO's business risk profile reflected its affiliation with AERG and CILCORP. Staff says it removed the incremental effect of both of those non-utility affiliates from AmerenCILCO's authorized ROR in accordance with Section 9-230 of the Act.

Staff states that using the S&P rating methodology, Ms. Phipps changed AmerenCILCO's business risk profile from "Satisfactory," which S&P stated reflected AmerenCILCO's non-regulated businesses, to "Strong," which was the less risky business risk profile that S&P assigned to AmerenCIPS and AmerenIP. Staff indicates that using the Moody's rating methodology, Ms. Phipps changed AmerenCILCO'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). According to Staff, Ms. Phipps concluded that AmerenCILCO's implied credit rating would increase by two notches (from A1 to Aa2) if its business risk profile were "Low" instead of "Medium." Given AmerenCILCO's actual senior secured debt rating from Moody's was Baa2 in December 2008, Staff says Ms. Phipps concluded that AmerenCILCO's secured debt rating would have been two notches higher, or A3, if AmerenCILCO's non-utility affiliates had not increased its business risk profile. Ms. Phipps recommends a 6.76% coupon rate for the bonds AmerenCILCO issued in December 2008, which reflects the average yield for A3/A- rated bonds during the same measurement period.

Staff indicates that in Docket Nos. 09-0306 et al. (Cons.), the Commission adopted this adjustment by Staff. Staff asserts that in the instant case, AIC mischaracterizes Staff's testimony when it alleges that Staff concluded that absent a single credit factor (i.e., AmerenCILCO's ownership of AERG), AmerenCILCO's credit ratings would have been higher and its cost of debt would have been lower. Staff contends that both of AmerenCILCO's non-utility affiliates – CILCORP and AERG – affected AmerenCILCO's credit ratings.

AIC alleges that since Fitch lowered AmerenCILCO's credit rating in May 2010 and Moody's affirmed AmerenCILCO's Baa3 rating following the transfer of AERG to another Ameren subsidiary, that one could conclude AmerenCILCO's ownership of AERG did not adversely affect AmerenCILCO's credit ratings or increase CILCO's borrowing cost. Staff argues that the recent downgrade to AmerenCILCO's credit rating by Fitch does not warrant revisiting the interest rate adjustment for the bonds that AmerenCILCO issued during December 2008. Staff says that 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. Staff believes the adjustment should not be based on subsequent events.

Staff also contends that several factors contributed to the downgrade of AmerenCILCO's issuer default rating, which makes it impossible to separate the net effect of one factor from other factors. Staff says Fitch acknowledged that the transfer of AERG lowered the business risk of AmerenCILCO and, at the same time it lowered AmerenCILCO's issuer default rating to BBB- from BBB, it affirmed the BBB- issuer default ratings of AmerenCIPS and AmerenIP. According to Staff, Fitch stated that commingling all the monies of AmerenCIPS, AmerenIP and AmerenCILCO supports equalization of the ratings given bondholders would share in a single pool of cash flow. Staff believes it is important that Fitch explained that AmerenCILCO's downgrade reflects the Commission's April 2010 rate order and the consolidation of AmerenCIPS, AmerenIP and AmerenCILCO, as well as management's plan to transfer AERG to an affiliate that owns other merchant generation assets.

AIC argues that Ms. Phipps considered historical metrics that were not adjusted to exclude AERG's meaningful cash flows. Staff responds that 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 AmerenCILCO. Staff claims AERG's $5 million net loss in 2005 had a negative effect on AmerenCILCO's consolidated net income and, in 2006, AERG's net income was slightly less than the contribution by AmerenCILCO's regulated Illinois segment. Staff also asserts that AmerenCILCO'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 AmerenCILCO. Staff says CILCORP paid approximately $31 million interest expense annually from 2005-2008 in connection with its outstanding indebtedness. Staff states that AERG's net income totaled $135 million from 2005-2008. In comparison, Staff says CILCORP interest expense totaled $130 million. Staff also contends that AERG cash flows were volatile in comparison to CILCORP's interest requirements. According to Staff, AmerenCILCO was squeezed between AERG's higher operating risk and additional financial risk from CILCORP. Staff claims that much of AERG's cash flows merely replaced the cash needed to service CILCORP's debt.

In its Reply Brief, Staff says AIC attempts to cast doubt on Ms. Phipps' evaluation of the rating that S&P would have assigned an AmerenCILCO with the same "strong" business risk profile as AmerenCIPS and AmerenIP, as opposed to AmerenCILCO's actual riskier business risk profile of "satisfactory"). Staff maintains that the same analysis of AmerenCILCO's implied standalone S&P credit rating was the basis for Staff's adjustment to the December 2008 bonds in the last case, which the Commission adopted.

Staff indicates that in the instant case, Ms. Phipps revised her adjustment in response to an AIC claim that Ms. Phipps' evaluation of the rating that Moody's would have assigned a standalone AmerenCILCO was flawed in that it combined Moody's 2005 and 2009 rating methodologies. Staff states that Moody's 2005 methodology was appropriate for evaluating the effect of adjusting AmerenCILCO's business risk profile given that AmerenCILCO's December 2008 debt issuance preceded publication of Moody's 2009 methodology. Staff says Ms. Phipps testified that the only distinguishable differences between those methodologies are (1) the 2005 methodology provided separate financial benchmarks for "Medium" and "Low" business risk profiles; and (2) the 2009 methodology discloses the weights that Moody's assigns each of the credit metrics. According to Staff, there is no indication that the weights Moody's assigns credit metrics in the 2009 methodology changed from the 2005 methodology. Nevertheless, Staff says Ms. Phipps re-evaluated the effect that changing AmerenCILCO's business risk profile from "Medium" to "Low" would have on AmerenCILCO's credit metrics without using those weights provided in the 2009 methodology.

In its Reply Brief, Staff also contends that AIC's arguments regarding the 2009 Moody's report on AmerenCILCO should be rejected given AIC's cost of capital witness admitted he is not familiar with the 2009 Moody's report that Ms. Phipps relied upon to support her adjustment. (Staff Reply Brief at 39, citing Tr. at 210) In Staff's view, AIC's arguments that a 2009 rating agency report would have mentioned the possible transfer or divestiture of AERG, which was not announced until 2010, are absurd.

AIC alleges that Ms. Phipps' hypothetical Moody's analysis would surmise had AmerenCILCO been a standalone utility, it would have been the highest rated utility in the United States by Moody's. Staff claims that AIC misrepresents the evidentiary record and that this statement is false and improper on two levels. First, Staff claims it assumes facts not in evidence; that is, the highest rating Moody's has conferred upon a utility. Second, Staff asserts the statement falsely alleges that Ms. Phipps concluded that AmerenCILCO would have been rated Aa2 had it been a standalone company. Staff argues that to the contrary, Ms. Phipps expressly stated that she did not conclude that AmerenCILCO would have been rated Aa2 on a standalone basis; rather, she increased AmerenCILCO's actual senior secured debt rating by two notches to A3, which is the difference in credit ratings implied by comparing AmerenCILCO's credit metrics to benchmarks for Medium risk versus Low risk utilities. Staff states that while it is correct that AmerenCILCO's financial ratios were commensurate with an Aa2 credit rating on a standalone basis, Ms. Phipps testified that credit ratings are also based on qualitative factors. Staff also says that while acknowledging that there is no way to replicate completely what Moody's would have done had Moody's issued a rating for a standalone AmerenCILCO, Ms. Phipps explained that a credit rating would not be very useful if it was not possible to evaluate how changes in circumstances would affect a given company's credit rating.

Regarding AIC's objections to Ms. Phipps' hypothetical Moody's analysis, Staff insists she explained that absolute certainty is not possible in any "what if" analysis, which by its very nature requires assumed conclusions for facts and events that did not exist. In this instance, Staff says the fact that did not exist in December 2008 was an AmerenCILCO that did not own AERG and was not a direct subsidiary of CILCORP. Staff reports that Moody's January 30, 2009 report is clear that Moody's did not rate AmerenCILCO as if it were a standalone company that did not own AERG and was not a direct subsidiary of CILCORP. Staff contends that Ms. Phipps found substantial evidence that AmerenCILCO would have had higher credit ratings in 2008 if not for its affiliation with AERG and CILCORP.

According to Staff, AIC erroneously argues that Ms. Phipps failed to consider the significant cash flows generated by AERG and characterizes her analysis as "asymmetrical." Staff insists that Ms. Phipps evaluated both AERG cash flows and the interest requirements of AmerenCILCO's intermediate parent company CILCORP and concluded that both of those affiliates negatively affected AmerenCILCO's credit rating. Staff also contends Section 9-230 does not prohibit incremental risk of non-utility affiliates to the extent there are no benefits to offset those incremental costs. Staff asserts that Section 9-230 prohibits including even one iota of incremental cost that results from non-utility affiliates. In Staff's view, even if this claim by AIC was correct, which it is not, it would have to be rejected because it would be based on a flawed interpretation of Section 9-230 of the Act.

Finally, Staff argues that no new facts have emerged that would cast doubt on Staff's methodology. Staff claims that if those alleged "new facts" had emerged three years after AmerenCILCO issued those bonds, and following a rate case in which the Commission already adopted an adjustment based on the facts that existed at the time of the debt issuance, the Commission's reliance on any new facts would constitute hindsight, which is inappropriate for ratemaking purposes. Staff maintains that the May 20, 2010 downgrade by Fitch does not warrant revisiting the adjustment to AmerenCILCO's December 2008 bonds, particularly because several factors contributed to that downgrade, and there is no indication that the divestiture of AERG was a "primary driver." According to Staff, AmerenCILCO's assets (excluding AERG) comprise a mere 16% of AIC assets. In Staff's view, it is not surprising that Fitch assigned AmerenCILCO the same rating as AmerenCIPS and AmerenIP in light of the announced merger of the three Ameren Illinois Utilities.

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

3. Commission Conclusion

As the Commission understands it, there are three contested issues relating to AIC's embedded cost of long-term debt. Those issues relate to the coupon rate for AIC's expected October 2012 bond issuance; the principal amount of AmerenIP's October 2008 bond issuance; and, the interest rate for the 8.875% bonds that AmerenCILCO issued in December 2008.

Both AIC and Staff appear to agree that the arguments relating to the coupon rate for AIC's expected October 2012 bond issuance are the same as those underlying their positions regarding the cost of short-term debt. As the Commission has already determined, by basing its estimate of the 30-day LIBOR rate on projected three-month LIBOR rates, AIC has in all likelihood overstated the interest rate. The Commission also found that Staff's proposal for estimating the cost of short-term debt should be adopted for purposes of this proceeding. As a result, the Commission similarly concludes that Staff's proposal to use a 4.4% interest rate for the October 2012 bond issuance is reasonable and should be used for purposes of this proceeding.

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. Staff says this adjustment is based on the Order from Docket Nos. 09-0306 et al. (Cons.) in which the Commission concluded that AmerenIP issued $50 million more in long-term debt than required for its utility operations during October 2008. AIC argues that its actions in October 2008 were prudent and that Staff has failed to provide any fact or expert analysis that would support its proposed adjustment pursuant to an applicable legal standard.

In Docket Nos. 09-0306 et al. (Cons.), the Commission addressed this issue. The Commission stated:

> It appears to the Commission that AmerenIP issued more long-term debt than required for AmerenIP's utility operations, 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's proposed long-term debt balance for AmerenIP for the purposes of this proceeding. Order (April 29, 2010) at 143.

The facts here are exactly the same and the Commission believes the results should be the same. The legal standard that apparently eludes AIC was previously stated. AIC's actions, if not adjusted in the ratemaking process, would unnecessarily burden ratepayers with $50 million in excess debt at a relatively high interest rate of 9.75%. Under the Act, AIC is allowed to recover from ratepayers a reasonable cost of capital but if allowed to pass on the cost associated with $50 million of relatively high cost debt that was not needed, the Commission finds that AmerenIP would effectively recover from ratepayers an excessive cost of capital.

In other words, if the Commission failed to make the adjustment proposed by Staff, ratepayers would be burdened with an unreasonable cost of capital. It appears to the Commission that while the mathematical calculation proposed by Staff in this case is different from that adopted in AIC's previous rate case, the result is the same. The Commission finds that Staff's proposed adjustment for the 2008 AmerenIP debt issuance is reasonable and leads to a cost of long-term debt that is reasonable and should be adopted for purposes of this proceeding.

With regard to AmerenCILCO's bond issuance in December 2008, in Docket Nos. 09-0306 et al. (Cons.), the Commission stated:

> Based on the evidence presented, the Commission can only conclude that there has been an increased cost to AmerenCILCO for long-term debt due to the presence of its unregulated affiliates, CILCORP and AERG. Staff has made a persuasive showing that but for these unregulated affiliates, AmerenCILCO would have been assigned a more favorable debt rating and would have been able to accomplish the December 2008 bond issue at a lower interest rate, as suggested by Staff. Therefore, the Commission will adopt Staff's proposed cost of long-term debt rate of 6.69% for AmerenCILCO, 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 (April 29, 2010) at 150-151.

Staff urges the Commission to make the same adjustment in this proceeding. AIC, on the hand, urges the Commission to revisit that decision and reach a different conclusion. AIC witness Martin argues that in May 2010, Fitch downgraded AmerenCILO's credit rating due, in part, to its divestiture of AERG. AIC believes that this effectively refutes the basis for the finding that AmerenCILCO's affiliation with CILCORP and AERG resulted in a higher cost associated with the December 2008 bond issue. According to Staff witness Phipps, however, AmerenCILCO was squeezed between AERG's higher operating risk and additional financial risk from CILCORP.

It appears to the Commission that AIC's argument depends largely on the May 20, 2010 decision by Fitch to downgrade AmerenCILCO's credit rating. Ameren Ex. 24.6. The Commission has reviewed this exhibit along with the related testimony and arguments. The Commission finds contradictory statements in Ameren Ex. 24.6. Fitch cites the loss of electric gross margin on merchant energy sales, suggesting an adverse impact on AmerenCILCO's credit rating. On the other hand, Fitch explicitly states that the transfer of AERG will reduce the business risk of AmerenCILCO. The Commission believes that many factors identified in Ameren Ex. 24.6 combined to result in Fitch's downgrading of AmerenCILCO's credit rating. The Commission finds AIC's suggestion that the divestiture of AERG contributed to the downgrade to be overly simplistic. From the record it is clear to the Commission that AERG increased the business risk of AmerenCILCO and CILCORP increased the financial risk of AmerenCILCO. The Commission concludes that Ms. Phipps proposed cost rate for the December 2008 AmerenCILCO bond issuance, 6.76%, is appropriate and should be adopted. This conclusion is consistent with the Commission's determination in the last AIC rate case and is consistent with the requirements of Section 9-230 of the Act.

G. Cost of Common Equity

Four parties presented the testimony of expert witness addressing AIC's cost of common equity. AIC offered the testimony of Mr. Hevert, Staff offered the testimony of Ms. Freetly, IIEC offered the testimony of Mr. Gorman, and AG-CUB offered the testimony of Mr. Thomas. The table below summarized the recommendations of those parties offering testimony on cost of common equity.

Cost of Common Equity
Summary of Recommendations

AIC	10.75%
Staff	8.90%
IIEC	9.25%
AG/CUB	8.22%

1. AIC Position

AIC indicates it will not attempt to address every disagreement regarding return on common equity ("ROE"), however, AIC believes there are a few core disputes that overshadow and overwhelm all others. AIC says it does not wish to distract attention from those disputes by drowning them in the customarily lengthy and turgid discussion of ROE.

In AIC's view, the three most significant differences among the parties’ means of arriving at ROE recommendations are: the third stage – or “steady state” or “terminal” – growth rate used in the multi-stage Discounted Cash Flow (“DCF”) analysis; the use of spot prices at one moment in time (instead of averages); and the ROE deduction proposed by Staff because AIC uses the uncollectibles expense rider authorized by the General Assembly. AIC claims that were the Commission to follow the decisions it has made recently involving other utilities, none of these would be an issue.

According to AIC, the evidence shows that it requires an ROE of no less than 10.5% for gas operations, Staff, however, contends that AIC should operate with historically low ROEs, just 8.9% for gas operations, lower than nearly all authorized ROEs nationwide during the last three years. AIC avers that Staff can arrive at its recommendations only through a disregard for what the Commission has been doing in other cases. AIC claims that treating it comparably to other companies on the third stage growth rate would increase Staff's recommendations by over 50 basis points, or roughly half the difference between the Staff and AIC recommendations. AIC also asserts that treating it comparably with ComEd regarding the uncollectibles rider would increase ROE another 16.25 basis points. AIC further claims that using average data instead of prices at the closing bell on what it describes as the randomly selected date of June 3, 2011 would also increase ROE.

AIC says it deserves fair treatment. AIC says the Commission cannot have one means of determining ROE for one company and a different set of rules for another. AIC wants the Commission to develop ROEs in a coherent, consistent manner. AIC wants the Commission to adopt AIC's requested ROEs that are supported by its expert, Mr. Robert Hevert. At the very least, AIC thinks the Commission should adjust the Staff's recommendations to reflect a proper third stage growth rate, the use of averages for data inputs and the rejection of Staff's "arbitrary and unjustified" deduction for the uncollectibles rider.

AIC states that based on the Commission's decision in Docket Nos. 09-0306 et al. (Cons.), Mr. Hevert relied on the multi-stage DCF model and the capital asset pricing model ("CAPM") as his primary analytical approaches. AIC says he also considered an alternative Risk Premium approach as a corroborating methodology.

a. DCF

According to AIC, DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. AIC states that in its simplest form, the DCF model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.

The multi-stage DCF model, ACI avers, sets the subject company's stock price equal to the present value of future cash flows received over three "stages." In the first two stages, "cash flows" are defined as projected dividends. In the third stage, "cash flows" equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the "terminal price"). In each of the three stages, the dividend is the product of the projected EPS and the expected dividend payout ratio.

AIC asserts that IIEC and AG/CUB proposed deeply flawed DCF analyses. AIC contends that IIEC witness Mr. Gorman submitted a constant growth DCF analysis that was of no relevance. AIC claims he also submitted a multi-stage DCF model that used inappropriate values for the terminal stage growth rate, dividend payout ratios and stock price. AIC asserts that AG/CUB witness Mr. Thomas proposes inappropriate and misguided adjustments to Mr. Hevert's multi-stage DCF.

AIC indicates that Mr. Hevert relied on average stock prices over 30, 90, and 180 trading days. AIC claims that this approach balances the need to reflect current information with the need to consider the volatility that may occur in stock prices on any given day.

AIC indicates that Ms. Freetly used a single stock price in her model, the closing price on June 3, 2011. AIC describes this as a price at a one moment in time. She asserts that the most recent stock price reflects the market's current perspective on a particular company given all the information that is known by investors on that particular date.

In AIC's view, the most significant flaw in Ms. Freetly's approach is that it 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. AIC states that for example, on May 6, 2010, the market sustained what has come to be known as the "flash crash," in which stock prices moved significantly during the course of the trading day without any specific information that would support such erratic movement. AIC asserts that while that is an extreme example, there is little question that events and information affect securities prices every day; at times, those effects can be due to unusual, extraneous factors. AIC argues that the use of spot prices on a particular day may cause the DCF results to be susceptible to volatile market movements that may not reflect the general market trends, whereas average prices are more insulated from aberrant or anomalous events.

AIC points out that in Docket No. 10-0467, the Commission noted that it had recently rejected use of such a pure spot date approach in its North Shore decision and notes the problems that can result from using such data. AIC says the Commission went on to note that the Staff witness improperly employed a spot date approach. According to AIC, that position is consistent with the Commission's Order in Docket Nos. 07-0241 and 07-0242 (Cons.).

In AIC's view, there is nothing in the record to indicate that there was anything special about June 3, 2011. AIC claims it was just a date roughly one month before Staff's testimony was due. AIC complains that Staff did not make any effort to explain why this was a particularly representative date. AIC claims Staff's approach fails to address volatility or randomness. AIC believes Staff has not justified the use of this particular date, and asserts the Commission is skeptical of spot prices. In AIC's view, there is nothing to justify Staff's approach and it should be rejected in favor of Mr. Hevert's averaging approach.

In its Reply Brief, AIC states that the results of Ms. Freetly's DCF analysis vary by as much as 80 basis points, and the results of her CAPM analysis vary by as much as 32 basis points over a period of less than one month. AIC says in a single day, between August 10, 2011 and August 11, 2011, Ms. Freetly's DCF results varied 20 to

24 basis points, and her CAPM results varied 8 to 12 basis points. AIC believes that while such volatility may not be of the same magnitude as seen in broad market indicators, it demonstrates that within the study period, analyses based on spot data continue to be subject to volatile results, and lead to unreliable calculations and results.

AIC argues that the use of an averaging period, such as the 30-, 90- and 180-day averages that Mr. Hevert relied on in his analyses, mitigates the variability in ROE estimates that results from choosing an individual spot price, and allows for consideration of data over more volatile periods, such as the current period. AIC also asserts that the use of average prices eliminates the subjectivity associated with choosing a particular day to best represent the cost of equity.

According to AIC, the single most significant way in which Staff and the other parties have skewed their ROE recommendations downward is with respect to the third stage or “steady state” or “terminal” growth rate. AIC complains that this bias in their analyses is particularly inappropriate given the Commission’s rejection of a comparable approach to calculating the steady state growth rate in its May 24, 2011 Order in the ComEd rate case, issued over a month before the Staff and Interveners submitted their direct testimony in this case.

AIC indicates that the third stage in a multi-stage DCF analysis begins after the 10th year and continues in perpetuity. AIC adds that there are two components to this steady state growth rate: real (i.e., not reflecting inflation) gross domestic product ("GDP") growth and inflation. It is with respect to the real GDP growth rate that most of the difference between AIC and the other parties lies.

AIC states that Mr. Hevert calculated a long-term growth rate of 5.66 percent based on the real GDP growth rate of 3.27 percent from 1929 through 2009, and an inflation rate of 2.31 percent, revised to 5.64 percent [((1+3.26%)*(1+2.31%))-1]. In determining the future real GDP growth rate, Mr. Hevert used a historical value – the GDP growth rate experienced by the United States over an 80 year period. AIC argues that there is no better indicator of GDP growth beginning in Year 11 and beyond than the actual historical growth that the country has experienced over a meaningful period of time.

AIC states that one month after the ComEd rate case Order was issued in Docket No. 10-0467, Staff filed its testimony in this proceeding, relying on the very same sources, for essentially the same future period, that the Commission rejected in the ComEd case in response to essentially the same historical growth rate. AIC says Ms. Freetly admitted that she did not take the ComEd order into account, and her only rebut of it was confined to a footnote. AIC repeats that the Commission rejected the sources she uses in favor of an historical growth rate, and when AIC proposed virtually the same historical growth rate to apply to the virtually the same future period, AIC says Ms. Freetly simply offered once again what the Staff unsuccessfully presented in the ComEd case. AIC says she stated that the Commission’s rejection of the Staff’s position in the ComEd case did not cause her to alter her analysis in any respect.

In AIC's view, this is not an instance of utilities being in different circumstances. AIC contends this is an instance involving general data applicable to the U.S. economy as a whole. AIC states this is an instance in which: 1) ComEd presented a 3.4% real GDP growth rate based on historical data to apply to a terminal stage beginning in 2020; 2) AIC has presented a 3.3% real GDP growth based on historical data to apply to a terminal stage beginning in 2021; and 3) Staff is arbitrarily recommending that AIC receive materially different treatment, without any explanation, much less justification. AIC believes there is no reasonable basis for such disparate treatment and the growth rates of Staff and the other parties should be rejected in favor of Mr. Hevert's terminal stage GDP growth rate.

AIC states that Mr. Hevert's third stage rate of inflation of 2.31 percent is based on the average of the long-term projected growth rate in the Consumer Price Index ("CPI"), as reported by Blue Chip Financial Forecast and the compound annual CPI growth rate projected by the Energy Information Administration ("EIA") in the 2010 Annual Energy Outlook. AIC says Ms. Freetly's projected inflation rate is higher, but the problem is her overall nominal growth rate. AIC complains that Ms. Freetly's estimate of long-term nominal GDP growth of 4.80 percent is 120 basis points lower than the Commission's Order in the ComEd case.

Ms. Freetly estimated a long-term inflation rate of 2.50 percent. In addition, Ms. Freetly noted that both EIA and Global Insights estimate that real GDP will average 2.60 percent over the long-term. AIC says that combining the projected real GDP growth rate of 2.60 percent and the expected inflation rate of 2.50 percent produces a 5.20 percent projected nominal GDP growth rate. Ms. Freetly also considered the average nominal GDP growth rate forecasts by EIA and Global Insight of 4.50 percent and 4.40 percent, respectively. In establishing her estimate of 4.80 percent, Ms. Freetly averaged (1) the estimated nominal GDP growth rate of 5.20 percent and (2) the average of the EIA and Global Insights forecasts of economic growth of 4.50 percent and 4.40 percent.

AIC states that changing the long-term growth rate in the terminal stage from 4.80 percent to 6.00 percent, using Ms. Freetly's electric and natural gas proxy groups, and holding all else constant would cause Ms. Freetly's multi-stage DCF results to increase from 9.55 percent to 10.47 percent for electric operations, and from 8.63 percent to 9.59 percent for natural gas operations.

AIC also states that the June 2011 edition of the <u>Blue Chip Financial Forecast</u>, which represents a consensus forecast of approximately 50 economists, projects the 30-year Treasury yield to average 5.70 percent for the period 2018-2022. AIC notes that none of the other sources cited by Ms. Freetly (i.e., EIA's Annual Energy Outlook, Global Insights 1st Quarter 2011 projections, or the Survey of Professional Forecasters) provides such projections.

According to AIC, if Ms. Freetly is correct that the 30-year Treasury yield is a proxy for expected long-term nominal GDP growth, the Blue Chip Financial Forecast projection of 5.70 percent is six basis points greater than Mr. Hevert's 5.64 percent projection. AIC notes that the Blue Chip projection is 90 basis points above Ms. Freetly's 4.80 percent long-term growth estimate. AIC suggests Ms. Freetly's position that long-term Treasury yields are a proxy for expected macro-economic growth supports Mr. Hevert's 5.64 percent estimate.

In its Reply Brief, AIC notes that IIEC relies, in part, on a constant growth DCF model. AIC says IIEC's constant growth DCF analyses produce results as low as 7.41 percent for electric utilities, and 7.31 percent for natural gas utilities. According to AIC, neither of those estimates is reasonable under prevailing economic or capital market conditions. AIC also asserts that the Commission has recently placed weight on the multi-stage DCF approach, while rejecting the sustainable growth rates used in Mr. Gorman's constant growth analysis. AIC believes Mr. Gorman's constant growth DCF approach should be disregarded, and the debate over whether Mr. Gorman's sustainable growth rate is appropriate becomes irrelevant.

AIC also claims that IIEC attempts to paint Docket No. 10-0467 as an anomaly and contends that the Commission has rejected the use of historical growth rates in another case, citing the Nicor decision in Docket No. 08-0363. According to AIC, this is IIEC's third attempt to find a case to show that Docket No. 10-0467 represented an anomalous departure from long-standing practice. AIC says previously, Mr. Gorman cited two different cases, neither of which AIC believes supported IIEC's position. AIC states that the first, Docket No. 05-0597, addressed the use of GDP growth rates (whether historical or forecasted) to estimate long-term growth in the constant growth DCF or two-stage DCF model. AIC asserts that none of the ROE witnesses in Docket No. 05-0597 proposed the use of a three-stage DCF model like the one that Mr. Hevert and Staff have proposed in this proceeding.

AIC asserts that in Docket No. 07-0566, which Mr. Gorman also cited, the Commission did not explicitly reject the use of historical GDP growth as the long-term growth rate in the multi-stage DCF model; rather, it rejected ComEd's proposed ROE of 10.75 percent, which AIC says was based on four DCF models, two CAPM analyses, and four risk premium analyses. According to AIC, three of the four quotes provided by Mr. Gorman in his rebuttal testimony are a summary of Staff's position and do not pertain to the Commission's analysis and conclusion. AIC says the growth rate that was explicitly rejected by the Commission in the Order in Docket No. 07-0566 was the average analyst growth rate, not the utility's proposed GDP growth rate of 6.60 percent.

According to AIC, IIEC contends that the 2009 Nicor decision elucidates two principles that AIC violates: 1) that the model reflect realistic expectations; and 2) that growth estimate inputs be reasonable estimates of long-term sustainable growth.

In AIC's view, IIEC misses the point completely. AIC argues that Mr. Hevert in this case, and the Commission in Docket No. 10-0467, put forth analyses that did reflect realistic expectations, and their growth estimate inputs were reasonable estimates of long-term sustainable growth. AIC contends there is no debate in this case over whether using GDP as a proxy for the terminal growth rate in a non-constant DCF analysis has merit. AIC insists that Mr. Hevert's analysis and the Commission's analysis in Docket No. 10-0467 capped the terminal growth rate for companies in the sample at the GDP growth rate. According to AIC, neither Mr. Hevert's analysis in this case nor the Order in Docket No. 10-0467 departs from whatever principles the Commission expressed in the Nicor order quoted above.

AIC believes the question is not whether to use a GDP growth rate in that terminal stage, but rather how to quantify that terminal stage GDP growth rate. AIC says Staff endorses the use of professional forecasters and rejects the use of a "mishmash of historical averages" as a basis for estimating future growth. AIC claims that what the Commission added to the development of its DCF approach in Docket No. 10-0467 was to express a well-founded skepticism that the growth rate for a period beginning 10 years from now and extending out decades would be materially lower than the growth rate we would see if we turned around and looked back over many decades at what the U.S. economy actually did. AIC also says Mr. Hevert did not average averages in his analysis, so his result (5.64%) does not represent any sort of "mishmash."

According to AIC, Staff contends that AIC's long-term growth rate is unreasonable because it implies ROEs for the proxy groups that are significantly higher than the ROEs for the proxy groups estimated by Value Line. AIC maintains that Staff's assertion is premised on the "b times r" approach to estimating growth, which assumes that internal growth is defined as the product of the retention ratio (b) and the earned ROE (r). AIC adds that in prior orders the Commission has found that approach to be unreliable. AIC believes Staff's assertion that Mr. Hevert's long-term growth rate is not sustainable is premised on a method that the Commission has rejected.

b. CAPM

AIC states that Mr. Hevert and Ms. Freetly agree on the general construct of the CAPM whereby a risk premium is added to a risk-free rate to determine the required ROR. The risk premium is calculated by multiplying the proxy group's average beta coefficient by the overall market risk premium. AIC says they also agree on the use of a prospective or ex-ante market risk premium, rather than a historical or ex-post risk premium. According to AIC, the major areas of disagreement between AIC and the Staff regarding application of the CAPM are: (1) the use of a spot risk-free rate; (2) the appropriate beta coefficient; and (3) the calculation of the expected return on the overall market, which is used to determine the ex-ante market risk premium.

AIC repeats that in prior orders the Commission has rejected the use of spot prices. AIC notes that in the recent ComEd rate case, Docket No. 10-0467, the Commission expressly rejected Staff witness Mr. McNally's use of spot risk-free rates. According to AIC, the Commission found that the use of a spot risk-free rate was unfair to the utility and lower than the risk-free rate investors demanded throughout the entire year (2010) at issue.

AIC asserts that Ms. Freetly's decision to use a spot risk-free rate as of June 3, 2011 is inappropriate for the same reason as using spot stock prices to calculate the stock price component of her multi-stage DCF analysis. AIC maintains that the use of a spot risk-free rate fails to smooth out the effects of daily trading behavior and market anomalies. According to AIC, the yield on 30-year U.S. Treasury securities ranged from 4.15 percent to 4.76 percent between January 1, 2011 and June 30, 2011. By using a spot interest rate, AIC says the CAPM result during the first six months of 2011 would vary substantially depending on the specific day the analysis was performed.

AIC also argues that the use of long-term, historical beta coefficients, such as the ones relied upon by Ms. Freetly is unreasonable. Value Line and Zacks both calculate Beta coefficients based on five years of data, which includes the period of the credit crisis and financial market dislocation. AIC asserts that during the credit crisis, the relationship between the broader market, as measured by the S&P 500, and utility stock returns was significantly different than during the period prior to the market dislocation. By relying on a five-year period, AIC contends that Value Line and Zacks beta coefficients underestimate the systematic risk that investors are compensated for in the CAPM analyses.

AIC asserts that Ms. Freetly's approach yields the lowest beta coefficients. AIC says the effect on the CAPM results of Staff's approach would be substantial. Assuming Ms. Freetly's 8.41 percent market risk premium, the difference in beta coefficients (electric) calculated using weekly returns with the S&P 500 Index (.81) and monthly returns with the New York Stock Exchange ("NYSE") index (.70) results in a difference in CAPM estimates of approximately 93 basis points ((.81 - .70) x .0841 = .00925), according to AIC.

AIC says while Mr. Hevert and Ms. Freetly agree that it is important to use forward-looking market risk premia rather than historical risk premia, and that the DCF model is a reasonable means of calculating the expected market return, in the CAPM, they disagree as to the appropriate methodology to estimate the expected return for the overall market, which is used to derive the market risk premium. Ms. Freetly begins with the companies in the S&P 500 and excludes those companies that do not pay dividends. While the calculation of the market risk premium that Mr. Hevert relies on is similar to Ms. Freetly's, AIC says he includes companies that do not pay dividends.

According to AIC, Ms. Freetly states that the 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. AIC claims the purpose of that analysis, however, is to estimate the expected return for the overall market. AIC contends it is appropriate to include as many companies as possible for which growth rate estimates are available, whether or not the company pays dividends. By doing so, AIC claims it is possible to gauge equity investors' return expectations for the entire universe of large capitalization companies. AIC also asserts that the constant growth DCF model, relied upon by Ms. Freetly in her calculation of the market risk premium, assumes constant payout and price/earnings ratios in perpetuity. AIC contends that the return to investors comes in the form of dividends and/or price appreciation. In AIC's view, it makes no difference whether or not a given company pays dividends.

AIC notes that Ms. Freetly's estimated market return is 12.67 percent, which is only 10 basis points different than Mr. Hevert's updated 12.77 percent estimate.

AIC notes that Mr. Hevert also calculated the market risk premium using all 1,560 companies in the Value Line universe, which AIC says Ms. Freetly relies upon in several aspects of her analyses, for which total return estimates are available. AIC says the market risk premium for the Value Line universe of companies ranges from 9.49 percent (simple average) to 10.51 percent (market-capitalization weighted average). AIC asserts that based on the results of that analysis, their respective 8.41 percent and 8.53 percent estimates are reasonable, if not conservative.

AIC asserts that in his CAPM analysis, IIEC witness Gorman employs an inappropriate market risk premium and improperly relies on Value Line as his sole source of beta coefficients. AIC contends that AG/CUB witness Thomas also proposes a number of inappropriate adjustments to Mr. Hevert's CAPM study.

c. Other ROE Models

AIC says Mr. Hevert performed additional modeling, the Bond Yield Plus Risk Premium approach, to confirm his ROE results. AIC states that in general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. According to AIC, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated for bearing that risk. AIC asserts that risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. Since the equity risk premium is not directly observable, AIC claims it typically is estimated using a variety of approaches. AIC says one alternative approach is to use actual authorized returns for electric utilities as the measure of the cost of equity to determine the Equity Risk Premium.

AIC indicates that Mr. Hevert examined data regarding allowed ROEs as derived from 483 electric utility rate cases from 1992 through December 31, 2010. According to AIC, his analysis showed that, based on the 30-day average of the 30-year Treasury bond yield and the near and long-term projections of the 30-year Treasury bond yields, the range of ROE results is from 10.56 percent to 10.99 percent, not including the effect of AIC's specific risk factors. AIC says this confirms the results of Mr. Hevert's DCF and CAPM analyses.

d. ROE Adjustments

AIC states that it employs a rider to smooth out recovery of its uncollectibles expense. AIC says the rider assures that it recovers no more or less than its actual costs. Staff contends that the presence of the rider reduces regulatory risk by reducing the likelihood that AIC will earn less than its approved return, and proposes that AIC's ROE be reduced by 16.25 basis points to reflect the effect of the rider on investor expectations. According to AIC, Staff purports to "calculate" this risk by predicting the effect of the rider on AIC's rating from Moody's.

AIC thinks Staff's proposed adjustment is unreasonable and inappropriate. AIC insists there is no empirical basis for Staff's assertion that the rider reduces risk. AIC argues that even if the rider does reduce risk, Staff's adjustment is not properly calculated. AIC asserts that Staff's proposed deduction would be far out of line with the treatment that other Illinois utilities have received. AIC says it would be 50% larger than the next largest adjustment. AIC recommends that Staff's adjustment be rejected.

AIC argues that the uncollectible rider does not reduce risk relative to other utilities. AIC says Staff argued in AIC's last rate proceeding that, historically, AIC under-recovered its uncollectibles expenses through base rates. AIC states that this was so because, until the last two years, the level included in the test year by the Commission was significantly below AIC's actual experience. AIC says the reasons for the under-recoveries varied, and included sharp commodity price changes and the impacts of a slumping economy, and are not relevant to this issue. According to AIC, what does matter is that, generally, where an expense is increasing (as uncollectibles expenses have), the use of historical average data will understate the amount of expense to be incurred in the future.

AIC says when a utility under-recovers its costs, it follows that, all other things being equal, the utility will not earn its authorized ROR. AIC states that the under-recovered expenses will reduce earnings to shareholders, dollar for dollar. In addition, AIC says under recovery puts pressure on future O&M and capital expenditures (since a company cannot continue to spend more than it recovers) and it tends to increase the cost of future financings (since the market views such situations as increasing risk to investors).

According to AIC, to address the difficulty of predicting uncollectibles expenses and accurately reflecting them in rates, the General Assembly adopted P.A. 96-0033, which authorizes the use of a rider to recover this expense. AIC says a rider ensures that the utility will recover its actual uncollectibles expense – no more, no less. AIC adds that this means that the utility's actual uncollectibles experience will not cause the utility to exceed or fall short of its authorized ROR.

AIC says it could not be unlucky forever, and in the last two years the level of uncollectibles expense collected through base rates has exceeded actual costs. This means that AIC has made refunds under the uncollectibles rider. According to AIC, the rider has not served to provide a means of covering a shortfall in base rates; rather, it has acted effectively to reduce base rates. AIC claims this is exactly what it said in the last case: the rider does not favor either AIC or customers. AIC asserts that it assures only that AIC will neither over-collect nor under-recover uncollectibles expense, which should be equally likely in normal circumstances.

AIC states that the adjustment, which flows from Staff's position in AIC's last rate case, is based on Staff's estimate of the effect the adoption of the riders would have on AIC's Moody's credit ratings, and particularly the effect on the utilities' ability to recover costs and earn returns. AIC asserts that Staff improperly assumes that approval of the uncollectibles rider would cause Moody's to increase AIC's credit rating by a full letter grade. AIC contends there are many elements that influence the score assigned by Moody's for the cost recovery factor, which accounts for 25% of the overall credit rating, and there is no evidence that the implementation of a single rider such as the EUA or GUA would cause Moody's to increase AIC's credit rating from Baa3 to A3, as Staff has assumed. AIC maintains that an improved political and regulatory climate in Illinois, which included the legislation providing Illinois utilities with a bad debt rider, cited by Moody's in 2009 resulted in only a one-notch upgrade by Moody's in AIC's credit ratings in 2009; thus, AIC believes the underlying assumption that Moody's would change both the "regulatory framework" and "sustainable profitability" factors by a full credit rating for the adoption of the riders alone was without merit. According to AIC, Moody's already had acknowledged the legislation and factored it into its decision to upgrade AIC to investment grade, so the actual adoption of the riders is unlikely to result in a full credit rating improvement in both regulatory framework and sustainable profitability. AIC asserts that Staff ignores this development, and others, since the Final Order in the last case.

AIC asserts that Ms. Freetly's proposed adjustment necessarily will be inexact, given that yields to maturity of utility debt issuances are highly variable, even after controlling for credit rating, collateral type and approximate years to maturity. AIC says Mr. Hevert conducted a search using the Bloomberg Professional Service for senior, unsecured utility bonds carrying an A- rating by one of the three major ratings agencies. AIC says he then calculated the approximate years to maturity of those utility bond issuances. Based on that analysis, AIC states that unsecured utility bonds show a wide variation in yields as of the most recent pricing date, even at the same credit rating. AIC adds that for bonds that have approximately five years remaining to maturity, from a group of 15 individual bond issuances, the minimum yield to maturity was approximately 2.03 percent and the maximum yield was approximately 3.25 percent, a difference of approximately 122 basis points. AIC also says that range is between 3.77 percent and 5.11 percent (134 basis points) for the five bonds with approximately 10 years to maturity, while 30-year bond yields diverge by approximately 84 basis points. Given that Ms. Freetly's adjustment attributes 65 basis points to the difference between two letter grades, AIC believes the fact that greater variation exists within one ratings notch demonstrates the imprecision inherent in her approach.

In AIC's view Ms. Freetly's proposed adjustment of 16.25 basis points, which assumes that the implementation of a tracker would result in a multiple notch credit upgrade, is unsubstantiated by Moody's ratings actions in the cases of the Illinois companies that have already implemented similar tracking mechanisms and is not supported by current utility bond market information.

In its Reply Brief, AIC says Staff suggests in its Initial Brief that there is some precision to its calculation. AIC asserts that Staff admitted in the last case that it knew of no precise way of measuring the effect of the uncollectibles rider on the cost of equity. AIC says Staff developed two methods – and averaged them, meaning that it was as confident in one as it was in the other. AIC adds that the Commission rejected one of the two methods, finding that it does not appear to provide a reliable estimate of the reduction in risk. According to AIC, Staff's estimates under the second approach were as much as 10 times the values that the Commission ultimately accepted. AIC says Staff was willing to accept estimates that differed by as much as 10 times as being equally reliable.

AIC thinks what this should tell the Commission is just what Staff said in the last case – there is no way to precisely calculate the effect of the riders, should the Commission not find that they are reciprocally beneficial. AIC argues that Staff's contention that it can precisely measure the effect of the riders and keep AIC at the same credit rating it would have without the riders is not only unfounded, but it is directly inconsistent with Staff's position in the last case that it could not gauge the precise effect of the riders.

AIC complains that Staff now argues that the riders are worth precisely three credit notches, and then it purports to calculate how many basis points three notches are worth. According to AIC, there are wide variations in how much a particular credit rating is worth. AIC says the market can assign very different values to the same rating. According to AIC, there is no example of a utility that was upgraded by one credit notch as a direct result of such a rider; the notion that AIC would receive a three notch upgrade has no foundation.

AIC believes there remains the problem of the differing treatment of different companies employing the very same rider. AIC says it faces an adjustment that is, as an arithmetic matter, infinitely larger than the zero basis point adjustment received by ComEd, more than double Nicor's and some two-thirds larger than Peoples. In AIC's view this is arbitrary and unreasonable, and there is nothing in Staff's Initial Brief to justify it.

AIC claims a recent Order involving Nicor highlights the unfairness. AIC states that in Docket No. 08-0363 Staff contended in that case that, had the rider been in effect for the prior ten years, Nicor would not have credited customers. AIC says Staff argued that the rider benefited the utility and proposed an adjustment to the ROE of 6.5 basis points.

AIC claims that in this case, where the utility has credited customers under the same rider in two of the last four years, and the value of the rider seems more symmetrical, Staff proposes an adjustment to the ROE of 16.25 basis points: exactly 2 ½ times the adjustment for Nicor's rider. AIC believes there can be no justification for such disparate treatment.

AIC also claims that Mr. Hevert also performed an "event study" that demonstrates that the implementation of a rider like the GUA does not have the effect that Staff attributes to it. AIC also believes Staff's recommended ROE adjustment is inconsistent with recent treatment received by, or recommended by Staff for, other utilities. In its recent rate case, concluded earlier this year, AIC says ComEd received no ROE deduction for its Rider UF, which tracks uncollectibles. According to AIC, Staff and Interveners did not even propose an ROE deduction in that case. AIC says Staff offers no justification in its testimony in this case for AIC being treated differently from ComEd. If Staff's rationale is correct, AIC suggests one would think it should apply equally to ComEd. AIC also states that in its most recent rate case (Docket No. 08-0363), concluded in 2009, Nicor ROE was reduced by 6.5 basis points for use of an uncollectibles rider. AIC says this is less than half the adjustment Staff proposes for AIC. AIC complains that Staff offers no justification for the disparate treatment received by Nicor. AIC says Staff is currently proposing a 10 basis point ROE deduction for Peoples in its pending rate case (Docket Nos. 11-0280 and 11-0281), which is just two-thirds of the adjustment that Staff is recommending in this case for AIC. AIC again complains that Staff offers no justification for its differing proposals.

e. Flotation Costs

AIC indicates that Ameren issued 21.85 million shares of common stock priced at $25.25 per share on September 15, 2009. AIC says that offering raised net proceeds of slightly more than $534.7 million, and Ameren incurred flotation costs of $17,001,375 (or 3.082 percent of gross proceeds) associated with the issuance, which have not been recovered through rates.

Ms. Freetly opposes recovery of flotation costs, citing a 1994 Commission Order in Docket No. 94-0065, which states that the Commission has traditionally approved [flotation cost] adjustments only when the utility anticipates that 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. In addition, Ms. Freetly is concerned that AIC's calculation of flotation costs is not based on actual issuance costs that AIC has incurred but not previously recovered through rates, but on the average costs of issuing equity that were incurred by Ameren and the proxy group companies in their two most recent equity issuances.

AIC argues that flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." AIC says they are not current expenses, and therefore are not reflected on the income statement. Rather, AIC contends that like investments in rate base or issuance costs of long-term debt, flotation costs are incurred over time, but remain part of the cost structure that exists during the test year and beyond. AIC says that although it does not issue common stock, it still must compete for equity capital with other Ameren affiliates. AIC contends that the common stock which has been issued by Ameren, the parent holding company, includes flotation costs, which are passed through to AIC. AIC claims its calculation of flotation costs includes the last two equity issuances for Ameren, and as such AIC believes it has met it burden of proof to demonstrate that it has incurred actual flotation costs that have not been previously recovered through rates. In AIC's view, it is appropriate to consider flotation costs in the determination of where AIC's ROE falls within the range of results.

2. Staff Position

Ms. Freetly measured the investor-required ROR on common equity with the non-constant DCF and 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 Mr. Hevert.

Staff states that 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, Staff says it must correctly reflect the timing of the dividend payments that a stock price embodies. Staff indicates that because the companies in Ms. Freetly's Gas samples pay dividends quarterly, Ms. Freetly employed a multi-stage non-constant-growth DCF model that reflects a quarterly frequency in dividend payments.

Ms. 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 EIA's and Global Insight's long-term forecasts of real 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. Staff says she then combined the resulting 5.2% growth estimate with the 4.5% average nominal economic growth forecasted by EIA and Global Insight.

Staff indicates that 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.

Staff indicates that Ms. 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 ROR 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 30-year U.S. Treasury bonds. Both estimates were measured as of June 3, 2011. Staff says 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 ROR 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 ROR 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. The Value Line regression employs 259 weekly observations of stock return data regressed against the NYSE Composite Index. Staff says 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. Staff says she then averaged that result with the Value Line beta, which produced a beta of 0.60 for the Gas Sample. Inputting those three parameters into the CAPM, Ms. Freetly calculated a cost of common equity estimate of 9.31% for the Gas sample.

a. DCF

AIC witness Mr. Hevert claims that average stock prices and bond yields should be used to estimate the investor-required ROR 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. In response, Staff asserts 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. According to Staff, historical data favors information that the market no longer considers relevant over the most recently-available information. Staff also asserts that historical data reflects conditions that may not continue in the future. Since stock prices reflect all current information, Staff believes only the most recent stock price can reflect the most recently available information. Staff insists that 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, Staff believes it is already incorporated into the most recent prices those investors pay for securities. In Staff's view, 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 also contends that Mr. Hevert's use of historical data includes the added flaw of inappropriately mixing and matching data from different points in time. Staff notes that the non-constant DCF from his rebuttal testimony, upon which his recommended investor-required ROR is based, employed average stock prices for the 30-, 90- and 180-day periods ending June 30, 2011. Staff adds that 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. According to Staff, 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. Staff maintains that 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 ROR. Staff claims 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. According to Staff, only a current stock price will reflect all information that is available and relevant to the market.

Staff argues that 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, Staff believes 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 also says the Commission has adopted costs of capital based on the most recent spot data much more frequently than it has relied on outdated historical data. According to Staff, the Commission itself has noted that use of spot data is a practice the Commission has traditionally relied upon and, in fact, is reluctant to deviate from.

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. If spot prices were sensitive to abnormalities, Staff claims one would expect the DCF estimates to jump around. Instead, Staff asserts that the DCF estimates reveal a trend that would be masked by the use of historical averages.

In Staff's view, 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. Staff believes 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 indicates that the Commission rejected use of historical stock prices in the Docket No. 03-0403 Order (Aqua Illinois, Inc., then Consumers Illinois Water Company, rate proceeding). Staff also says that in the last rate proceedings for AIC, the Commission rejected AIC's DCF analysis stating that the over-reliance on historical data is problematic. Consistent with the findings in the previous AIC rate cases, Staff believes Mr. Hevert's use of historical data in his cost of common equity analysis should also be rejected in this proceeding.

In its Reply Brief, Staff notes that AIC argues against the use of spot prices, claiming that this fails to account for aberrant behavior in stock prices. Staff claims that by measuring the cost of common equity at several points in time, Staff demonstrated that stock prices were not aberrant. Staff says the DCF-derived estimates of the cost of common equity for the gas sample can be explained by trends in the broader market. Staff maintains that current market price data must be used to determine the investor-required ROR on common equity because market data continuously adjusts to reflect investor return requirements as they are continuously re-evaluated. Staff claims average prices from as long as six months ago do not capture current investor expectations and could reflect information that investors no longer consider relevant.

According to Staff, the Commission has repeatedly ruled against the use of historical data in estimating the forward-looking cost of common equity estimate. The cases that AIC cites where the Commission rejected Staff's use of spot prices, Docket No. 10-0467 and Docket No. 07-0241 and 07-0242 (Cons.), are exceptions to the rule.

Based on the Commission's language in Docket Nos. 07-0241 and 07-0242 (Cons.), Staff claims the Commission is not opposed to using spot data at all; to the contrary, it deviates from the practice of using spot data only with reluctance. Staff states that the standard established in that order for deviating from that Commission ratemaking practice – when it can be shown that the proxy itself strays from a zone of reasonableness to the degree where it offers an unreliable estimate of the appropriate ROE - has not been met in this proceeding.

According to Staff, in the last rate case proceedings for AIC, AIC's witness used historical data to estimate the dividend yield in her DCF model. Staff says the Commission found Ms. McShane's over-reliance on historical data to be problematic and rejected her DCF analyses. Here, Staff believes the Commission should once again reject AIC's non-constant DCF analysis due to its over-reliance on historical data, particularly given that Staff has demonstrated that spot stock prices have not produced "aberrant" estimates.

According to Staff, the principal difference in the application of the multi-stage DCF is the long-term growth rate. Staff says 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, Staff believes this approach fails to take into consideration two crucial factors: the expected ROR on new investment (i.e., earnings) and the rate of earnings reinvestment (i.e., "retention"). Staff says the importance of these two factors should be obvious. Staff states that 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. Staff adds that 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, Staff claims Mr.

Hevert's assumed earnings retention ratio~~s~~ of 30.39% for his gas sample are too low to sustain the long-term growth rates he employs.

Staff contends that 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 18.63% for his gas sample. Staff indicates that Value Line projects a ROR on common equity of 11.95% for his gas sample for the 2013-2015 period. Staff says 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. Staff asserts that in order to sustain 6.00% growth given Mr. Hevert's assumed retention rates (revised in rebuttal), the companies in Mr. Hevert's 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. In response, Staff says the "b times r" formula provides insight as to what level of growth is sustainable because it can be used to estimate the expected ROR on new common equity investment for a given growth rate, which is necessary for assessing sustainable growth on a company-specific basis. Staff says 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, Staff claims that analysis is not expected to produce implied ROEs precisely in line with the costs of common equity recommended in this proceeding. Staff contends that 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, Staff suggests that Ms. Freetly's use of the "b times r" approach serves as a reality check on the level of growth that is plausible.

Mr. Hevert points out that Ms. Freetly's recommended return for AIC's gas operations is lower than the Value Line projected ROE. Staff contends it is important to understand that the expected ROR on new common equity investment "r" and the investor-required ROR on their common equity investment are not identical concepts. Staff says the former can include both projects that are expected to earn more than the required ROR and those that are expected to earn less than the required ROR.

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. In response, Staff asserts that this forecasted 30-year U.S. Treasury bond yield overstates long-term economic growth. Staff states that 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 Staff believes there is no reason to employ a proxy. Staff says 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%. Staff suggests that 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. Staff asserts that therefore, the Blue Chip forecast of 2021 30-year U.S. Treasury bond yields overstates the expected long-term growth rate of the economy.

Staff states that 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. Staff maintains that the investor-required ROR is a function of investor expectations of the future, not a mish-mash of historical averages. Staff says 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. Staff witness Ms. Freetly used those forecasts of nominal economic growth in calculating her 4.80% long-term growth rate. Staff contends that 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.

In its Reply Brief, Staff maintains that AIC fails to acknowledge that the growth rate accepted by the Commission in Docket No. 10-0467 was an abrupt departure from prior Commission findings, including the previous ComEd rate case, Docket No. 07-0566. Staff says in Docket No. 07-0566, the Commission rejected ComEd's long-term growth rate, which was derived in a nearly identical manner to the one accepted in Docket No. 10-0467, in favor of Staff's long-term growth rate which was derived from current market data. According to Staff, that Order states "in his non-constant DCF analysis, [ComEd witness] Hadaway used a historical GDP of 6.5% as his estimate of future GDP. Published expectations of future GDP growth are much lower." Staff says the Commission Order ruled that Hadaway's historical GDP growth rate was overstated and accepted Staff's 5% growth rate. Staff states that in Docket No. 10-0467, the Commission reversed itself and ruled that Staff's GDP growth rate was too low because it was inconsistent with actual historical growth for the U.S. economy and accepted ComEd's historical GDP growth rate. Staff contends that the Order in Docket No. 10-0467 provides no explanation or justification for the contradictory decision with regard to the proper long-term growth rate for the non-constant DCF analysis. Staff believes AIC's repeated cites to the Order in Docket No. 10-0467 as the one the Commission must adhere to when setting the investor required ROR on common equity should be disregarded. Staff maintains that the ComEd Order in this regard represents an exception to Commission precedent in determining the long-term growth rate. Staff recommends that the Commission adopt its long-term growth rate which was derived from current market data, consistent with the preponderance of Commission orders on the issue.

b. CAPM

Mr. Hevert insists that the estimation of the risk-free rate should not be based on spot yields. Staff contends that interest rates are constantly adjusting, and accurately forecasting the movements of interest rates is problematic. Staff says that 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. According to Staff, investor appraisals of the value of forecasts are also reflected in current interest rates. Staff contends that if investors believe that the forecasts are valuable, that belief would be reflected in current market interest rates. Staff also asserts that if investors believe that the forecasts are not valuable, that belief would be reflected in current market interest rates. In Staff's view, 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.

Staff believes it is important to note that T-bond yields reflect market forces, while forecasts do not. Staff says the true risk-free rate is reflected in the return investors are willing to accept in the market. As of June 3, 2011, Staff claims investors were willing to accept a 4.26% return on T-bonds, which includes an interest rate risk premium associated with its relatively long term to maturity. Staff asserts that because the T-bond yield includes such a premium indicates that the true long-term risk-free rate is actually below 4.26%. Staff recommends that the Commission continue to rely on current, observable market interest rates in the risk premium analysis. Staff says 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.

Staff states that 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. Staff asserts that 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. Staff says the same Blue Chip forecast projects that growth in real GDP and inflation are expected to remain relatively flat. According to Staff, 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). Staff says an increase in the interest rate risk premium should not be reflected in the risk-free rate. Staff also says a flow of funds from Treasuries to common stocks would result in higher stock prices and lower dividend yields.

Staff claims it is important to note the concurrent decline in Treasury yields with a decline in stock prices. Staff insists that it is important to update 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.

In its Reply Brief, Staff says in the ComEd Rate case, ComEd argued that Staff's "spot" risk-free rate on September 22, 2010 was unfair because it was lower than the "spot" rate on December 29, 2010. Staff states that here, Ms. Freetly used a 4.26% "spot" risk-free rate as of June 3, 2011. Staff also indicates that by mid-September, 2011, the 30-year Treasury bond "spot" risk-free rates were in the mid- to upper- 3%

range, depending on the day. Staff claims that AIC did not ask for the Commission to follow the ComEd Order in this respect since more recent interest rates are lower than those reflected in Staff's analysis. In Staff's view, AIC is not consistent in its advocacy of findings consistent with that Order.

Staff claims that in Docket Nos. 07-0241/07-0242 (Cons.), the Commission accepted Staff's CAPM methodology which was based on a risk-free rate estimate from a single day, despite the Commission's rejection of spot prices for the DCF analysis in that case. In addition, Staff says the Commission accepted Staff's CAPM analysis in AIC's last rate case and noted that the current yield on long-term U.S. Treasury bonds is an appropriate proxy for the risk-free rate. Staff urges the Commission to accept Staff's risk-free rate since it reflects the current market forces that impact the investor-required ROR on common equity.

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. According to Staff, Mr. Hevert claims that a near-term calculation better reflects the current relationship between the proxy group companies and the S&P 500. Staff believes there is an 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. Staff states that 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. Staff says 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.

Staff argues that 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. Staff says 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. Staff contends that 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. Staff says those counter-intuitive results are a consequence of the inverse relationship between risk and stock values. Staff states that as the risk of a stock declines, its price rises, all else equal. Staff asserts that in a rising stock market, the beta calculated will rise for a stock that is declining in risk, all else equal. Staff claims that in a declining market, the beta calculated will decline for a stock that is increasing in risk. Staff insists that a longer measurement period should be used as a more complete business cycle will include both rising and falling markets, reducing measurement error.

According to Staff, Ms Freetly illustrated the inherent volatility when calculating beta using only one year of data with 52-week betas for American Electric Power ("AEP"). Staff says the 52 week adjusted beta was 0.80 for 2004, rose to 1.02 for 2005 and then fell to 0.58 for 2006. Staff indicates that 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. Staff believes 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.

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. Staff says 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. Staff asserts that which beta estimates are more accurate is unknown. Staff states that different beta estimation methodologies can produce different betas when those methodologies employ different samples of stock return data. Staff contends that 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 indicates that Mr. Hevert developed two estimates of the market risk premium. 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. According to Staff, the dividend growth rate of non-dividend paying companies cannot be both constant and equal to the earnings growth rate as Mr. Hevert's estimation process assumes. Staff states that if the dividend growth rate is constant, it must remain 0%. Staff says the average dividend growth rate of the non-dividend paying companies in Mr. Hevert's analysis equals 15.04%. Staff argues that 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.

In its Reply Brief, Staff argues that despite criticizing Staff's use of spot stock prices in the DCF analysis and spot U.S. Treasury bond yields in the CAPM, Mr. Hevert relied on spot prices to calculate the required ROR on the market. According to Staff, this is inconsistent with AIC's professed criticism that spot prices fail to account for aberrant behavior in stock prices.

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. Staff says Mr. Hevert relied on data from 1926 through 2009 to estimate the historic risk premium and market volatility. Staff says Mr. Hevert then estimated the expected market risk premium ("EMRP") as the product of the historical risk premium, historical Sharpe ratio and estimates of expected market volatility. According to Staff, 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. Staff argues that 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. Staff says that according to the CBOE, VIX and VXV are not pure measures of expectations; they include a risk premium which varies over time. Staff says the CBOE also states that empirical evidence indicates that the risk premium for volatility is negative, which partly explains the continual historical bias of VIX over realized volatility.

Staff maintains that the use of historic data in estimating the forward-looking risk premium is fraught with problems. Staff says the magnitude of the historical risk premium depends upon the measurement period used. Staff contends that no proven method exists for determining the appropriate measurement period. Staff believes historical earned rates of return are questionable estimates of the required ROR that are susceptible to manipulation.

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%. Staff asserts that 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.

According to Staff, the Commission rejected use of historical data in Docket Nos. 06-0070 et al. (Cons.), a previous rate proceeding of AIC and specifically rejected AIC's estimate of the market risk premium. Staff also says that in Docket Nos. 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 ROR on common equity for the market. Staff urges the Commission to reject Mr. Hevert's use of historical data in his cost of common equity analysis in this proceeding.

c. Adjustments to Calculated ROE

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. Staff contends that these cost recovery mechanisms ensure more timely and certain collection of bad debt expense, thereby providing greater assurance that AIC will earn its authorized rates of return. Staff believes it is appropriate for the Commission to reduce the ROR on common equity to recognize the reduction in risk associated with the use of the uncollectibles riders.

Staff says Ms. Freetly's proposed adjustment for Rider~~s~~ GUA reflects the approach accepted by the Commission in the last AIC rate cases. She estimated the effect Rider~~s~~ GUA would have on the Company's Moody's credit ratings and based her adjustments on the resulting change in the implied yield spreads. Staff states that 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. Staff asserts that a rider designed to reduce uncertainty in cash flows would positively affect the cost recovery factor. Staff says 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. Staff says since this factor composes 25% of the overall weighting, raising the score for this factor by one credit rating suggests that AIC's ROE should be reduced by 25% of the spread between AIC's current rating and the next higher credit rating. Staff indicates that the June 14, 2011 spread between the Company's Baa3 rating and the A3 was 65 basis points. Ms. Freetly concluded that AIC's ROE should be reduced by 16.25 basis points (25% * 65 = 16.25) to reflect the reduction in operating risk stemming from Rider~~s~~ GUA.

In its Reply Brief, Staff notes that AIC argues that Staff's proposed adjustment is unreasonable because it is higher than the reduction authorized for other Illinois utilities with uncollectible riders. Staff responds that its proposal is not a static adjustment to apply to each utility that implements an uncollectible rider. Staff says its proposed adjustment is made in the context of spreads between bonds with different credit ratings in order to reflect the company-specific reduction in risk that will occur as a result of the implementation of the uncollectible rider.

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. Staff believes Mr. Hevert's analysis is irrelevant. Staff says 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. Staff says Mr. Hevert's analysis relied on individual bond yields that Staff believes are not directly comparable rather than an index of securities. Staff says 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. In Staff's view, 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 AIC being more assured of earning its authorized ROR.

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. Staff states that 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.

Staff believes that 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. Staff claims 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. Staff says 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. Staff complains that Mr. Hevert's 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. Staff contends that it is difficult to separate the effects of individual rider adjustments. Staff also asserts that Mr. Hevert did not investigate the reasons for large changes in DTE Energy Company's ("DTE") 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 during his event period.

Staff next complains that Mr. Hevert set the "event date," arbitrarily. Staff believes that if the "event date" is too early, then pre-rate decision factors will dilute the effect of the rate order on risk, but 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 contends that event period uncertainty causes event studies of regulatory changes to have low power in detecting any impact. According to Staff, 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.

Staff next asserts that 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. Staff suggests that 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. Staff says this article concludes that event studies of regulatory changes are difficult to conduct in a way that is unassailable.

Staff states that Mr. Hevert's event studies rely on the stock returns of DTE, the parent company of Detroit Edison and MichCon, which Staff believes creates another infirmity. Staff says 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. According to Staff, MichCon's net income was only 15.79% of DTE total net operating income. Staff contends that 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's stock returns.

To estimate the financial risk adjustment to the Gas samples, Staff says 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 utilities. Staff states that 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.

Staff claims that 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.

According to Staff, financial theory posits that investors require higher returns to accept greater exposure to risk. Staff says the investor-required ROR is lower for investments with less exposure to risk. Staff avers that 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. Staff concludes that 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.

Using 30-year utility debt yield spreads published by Reuters, Staff says Ms. Freetly calculated the yield spreads between the credit ratings implied by the financial ratios for AIC and those of the Gas samples. Staff indicates the spread between the implied ratings of Baa1 for AIC and the A3 for the Gas sample is 30 basis points. To determine the cost of common equity adjustments, Ms. Freetly multiplied the yield spreads by 30%, which Staff says is the percent of the overall credit rating that Moody's assigns to the financial ratios. Staff indicates that 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.

Mr. Hevert claimed that Ms. Freetly failed to consider company-specific business risk in comparing the risk of AIC to that of her Gas samples. Staff says 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. According to Staff, 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. Staff also asserts that Ms. Freetly compared the Standard & Poor's business profile scores for AIC and the Gas samples. Staff says 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. Staff states that the average business risk profile of Staff's Gas sample~~s~~ is also "excellent." Staff concludes that its samples are comparable to AIC in terms of business risk. Staff also notes with regard to the lack of weather normalization, AIC is allowed to recover 80% of fixed costs through rates. Staff claims this high level of fixed cost recovery mitigates the need for weather normalization as it largely decouples rates from usage.

d. Flotation Costs

Staff believes the flotation cost adjustment proposed by Mr. Hevert is inappropriate. Citing the Commission Order from Docket No. 94-0065, Staff says 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. Staff also emphasizes that the utility has the burden of proof on this issue. According to Staff, 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. In Staff's view, AIC has done neither.

Staff says Mr. Hevert’s flotation cost calculations were based on the costs of issuing equity that were incurred by Ameren and his sample group companies in their two most recent common equity issuances. Staff states that based on those issuance costs, he calculated a flotation cost of 0.13% for the natural gas distribution operations. According to Staff, 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.

Staff says the Commission has repeatedly rejected generalized flotation cost adjustments in previous cases as an inappropriate basis for raising utility rates. Staff argues that since Mr. Hevert’s calculation is not based on issuance costs that AIC has incurred but has not previously been recovered through rates, it should not be considered in setting the investor required ROR on common equity.

3. IIEC Position

IIEC witness Mr. Gorman recommends that the Commission award AIC a ROE for gas operations of 9.25%, which is the midpoint of his 8.85% to 9.60% estimated range of AIC current market cost of common equity for gas operations. IIEC says his recommendations were based on the results of a constant growth DCF model, a sustainable growth DCF model, a multi-stage growth DCF model, and a CAPM analysis. According to IIEC, these analyses used observable market information for a group of publicly traded gas utility companies. IIEC believes those samples of companies approximate the investment risk of AIC's gas operations.

In addition to their analyses and cost of equity estimates, IIEC notes that Mr. Gorman and Mr. Hevert presented reviews of relevant market conditions that were used as checks on the appropriateness of their estimates or to select point estimates within the ranges produced by their analyses. Mr. Gorman found the credit rating outlook for gas utilities is strong and supportive of the industry’s financial integrity. IIEC says his review of the industry market outlook showed that gas utilities' stocks exhibited strong return performance and are characterized as "safe haven" investments.

Focusing on AIC specifically, IIEC says that AIC's credit standing is impacted by its consolidation with its parent and affiliate companies. IIEC asserts that because of its low risk, pure transmission and distribution operations, AIC is considered a low operating risk business within the Ameren structure. IIEC further contends that AIC's regulatory/legislative risk is improving, notwithstanding comments to the contrary in some financial publications. IIEC claims AIC's regulatory uncertainty was largely based on credit analysts' concerns with legislative actions relating to the state's transition to competition. IIEC also asserts that more recent concerns can be traced to AIC's decision to use a historical test year with aggressive adjustments, rather than pursue less risky rate case filing options such as a future test year.

Mr. Hevert's review of the market emphasized data he presented as measures of volatility and investor risk perceptions. According to IIEC, he concluded that these measures indicate an increased cost of equity in capital markets. IIEC says Mr. Hevert does not claim or demonstrate that his general finding applies equally to regulated distribution utilities. IIEC believes such a claim would ignore the market's perception of utilities as safe havens during periods of market uncertainty and historically low interest rates, the current environment. IIEC disagrees, asserting that capital market costs have declined, particularly since AIC's last rate case and noting specifically the observable decline in "A "and "Baa" rated utility bond yields.

In its Reply Brief, IIEC states that rather than discuss any perceived weaknesses in IIEC's analysis, AIC's Initial Brief focuses instead on dire warnings to the Commission, pleas for "what the other guy got," and a request for "something extra" in its return award. IIEC says AIC warns the Commission of possible Wall Street reaction if it does not receive a high return, apparently without regard to what the record requires. Citing Docket No. 10-0138, IIEC urges the Commission to be independent of pressure to please investors at the expense of record-based decision making and fairness to ratepayers.

After estimating AIC's market required cost of equity, IIEC's Mr. Gorman verified that his recommended cost of equity was adequate to maintain an investment grade bond rating and financial integrity for AIC. His analysis compared key credit rating financial ratios for AIC, at the capital structure proposed by AIC and the return on equity Mr. Gorman recommends.

Mr. Hevert criticizes Mr. Gorman's evaluation of AIC's financial integrity at IIEC's recommended return level. He states that the credit metrics Mr. Gorman developed would support an investment grade bond rating even at a return on equity of 5%, concluding that this calls into question whether the evaluation is meaningful in determining whether that return on equity will support AIC's credit ratings. According to IIEC, that assessment of Mr. Gorman's evaluation is a bare mathematical exercise that ignores the more important aspects of Mr. Gorman's evaluation.

IIEC says Mr. Gorman's evaluation of metrics begins only after he has estimated a return on equity for AIC. According to IIEC, the evaluation is based on both an assessment of the current market cost of equity for AIC and the metrics-based assessment of whether or not the estimated fair return on equity and capital structure will support AIC's credit rating and financial integrity.

Mr. Hevert's argument suggests that the market does not distinguish among securities or review actual financial ratios, as long as the firms are in the same ratings category. IIEC insists that is not true. IIEC asserts that a return on equity of 5% does not produce strong credit metrics, when compared to IIEC's recommended return on equity of 9.85%. IIEC maintains that credit metrics based on a 5% return are categorically weaker than those produced by IIEC's recommended return.

In IIEC's view, Mr. Hevert's calculation of these ratios at a 5% return on equity does show that there is flexibility in the returns adequate to maintain supportive financial ratios, a point that is inconsistent with AIC's insistence that only its recommended return will preserve its financial integrity. IIEC maintains that its recommended return on equity of 9.85% provides an opportunity for AIC to achieve strong credit metrics, giving strong support to its investment grade bond rating, while providing fair compensation for the utility. Mr. Gorman also reviewed the cost of equity estimation analyses performed by Mr. Hevert. IIEC claims his findings indicated that his proposed return levels for AIC (both electric and gas operations) are overstated and unreasonable.

IIEC asserts that Mr. Hevert's multi-stage growth DCF analysis is based on a long-term growth rate estimate that is inflated and does not reflect current market participants' growth outlook. IIEC believes this inflated long-term growth rate input produces an overstated DCF estimate. IIEC also contends that Mr. Hevert's CAPM return estimates are based on unrealistic and inflated market risk premiums and flawed beta estimates that do not reflect long-term investment risk characteristics of regulated utility operations. IIEC says his analyses do not produce reliable CAPM return estimates. In IIEC's view, Mr. Hevert's bond yield plus risk premium model is based on an inflated equity risk premium and produces an unreasonable return estimate.

Mr. Gorman also offered proper adjustments to eliminate some of the deficiencies in Mr. Hevert's return studies. According to IIEC, they result in more reasonable and balanced return on equity estimates. IIEC asserts that Mr. Gorman's modest corrections to Mr. Hevert's studies show that a fair return on equity for AIC in this case is less than 9.5% for gas.

In its Reply Brief, IIEC says that AIC argues that if the Commission would only give it what ComEd got, its problems in this area would disappear. According to IIEC, AIC does not show that such findings would be supported by this record or are warranted for AIC. In addition, IIEC maintains that decision represented a departure from the Commission's longer-standing "coherent, consistent manner" of determining a utility's cost of equity. IIEC also says that AIC presumes to instruct that the Commission should be setting rates in a way that allows AIC to put some breathing room between it and sub-investment grade status, characterizing its current ratings position as daredevil, tightrope-walking regulation. According to IIEC, AIC warns that if an investment-grade credit rating is not maintained, AIC's borrowing costs - costs that are ultimately borne by ratepayers - will increase. IIEC contends no party has proposed a loss of investment grade status. IIEC says every party has conducted analyses that show their proposed returns will maintain AIC's credit rating.

IIEC also contends that AIC refuses to acknowledge that Staff's and IIEC's return on equity recommendations are low today because capital market costs for utility companies are at historically low levels. IIEC claims that observable utility bond costs dropped in this case relative to the last case. IIEC also says that in AIC's last case, a "Baa" utility bond yield was 6.92%; in this case, the cost of the same bonds is 5.92%. IIEC believes this indicator of AIC's cost of capital is clearly observed to be at least 100 basis points lower in this case than it was in the last case. To the extent bond rating analysts expect rational regulatory outcomes, IIEC says the Commission must recognize this change in the cost of capital. If the Commission does not recognize a cost decrease, when capital costs increase, IIEC claims credit rating agencies and the markets will not have confidence that the Commission recognize the change in costs to a higher cost of capital.

According to IIEC, AIC challenges other parties' findings that their lower cost of equity recommendations reflect that AIC is not as risky as the utility contends through its recommendation. AIC argues that other parties' recommendations are not logically consistent with its observations on the market. IIEC contends that the parties' assessment of the relative risk of AIC against the market and treasury instruments is simply that AIC is one of the safer investments in the market. In IIEC's view, there is no logical inconsistency in recognizing that Treasury instruments, because of their unique status, are even less risky.

IIEC alleges that acknowledging the outlier status of its cost of equity recommendations, AIC's Initial Brief emphasizes different, lower costs of equity. IIEC says AIC now advocates prominently for the low end of Mr. Hevert's ranges of estimates. IIEC contends that despite this unexplained change, AIC's range of cost of equity estimates remains unreasonably high.

a. DCF

Mr. Gorman's analyses included a constant growth DCF model using analysts' forecasts, a constant growth DCF model using a sustainable growth rate, and a multi-stage non-constant growth DCF model. The three results are averaged to produce Mr. Gorman's DCF estimate, which defines the lower end of his range of reasonable cost of equity estimates.

IIEC reports that after reviewing Mr. Hevert's testimony on cost of equity estimation analyses and his response to the critiques of non-utility experts, Mr. Gorman concluded that the differences between Mr. Hevert's approaches and other parties' DCF studies relate to fundamental arguments about the elements of a proper estimation of reasonable and reliable DCF returns. According to IIEC, the input that sets Mr. Hevert's DCF analyses apart is his excessive long-term growth rate, which raises his estimates.

IIEC states that the constant growth DCF model requires a growth rate that can be sustained over an indefinite period. IIEC also indicates that the final stage of a multi-stage DCF model similarly requires a growth rate that is sustainable over the infinite period as the model is designed on the assumption this growth will hold constant into perpetuity. According to IIEC, in Mr. Hevert's criticism of other experts' analyses and in his own DCF input choices, he dismisses that basic requirement. IIEC also contends that Mr. Hevert appears not to accept that when growth rates fail customary tests of sustainability and rationality, the DCF model will produce unreliable results.

IIEC believes that principles underlying DCF models that should continue to be followed by the Commission include: (i) requirements that the model reflect realistic expectations; and (ii) that growth estimate inputs be reasonable estimates of long-term sustainable growth. IIEC contends that Mr. Gorman's DCF models respected these constraints. IIEC says Mr. Gorman assessed the analysts' growth rates used in his constant growth model and determined that they are not sustainable, as they exceeded the projected growth rate of the entire U.S. economy, as represented by the GDP. IIEC reports that he also concluded that because of the excessive growth rate the model was not reliable as the sole basis for a cost of equity estimate. IIEC says he continued his analysis by using, in addition, sustainable growth and multi-stage DCF models.

IIEC states that the sustainable growth DCF model is a constant growth DCF model, but the growth rate used in the model is developed based on internal growth plus external growth factors that can be sustained indefinitely by companies. According to IIEC, a company's growth is fueled by its reinvestment of earnings and new investment. IIEC says the funds available for reinvestment are in turn tied to how much of the company's earnings are paid out in dividends. IIEC states that difficulties with ascertaining market outlooks are for the factors underlying this growth estimate, require that this model also not be the sole basis for a cost of equity estimate. IIEC says Mr. Gorman completed his analysis with the addition of a multi-stage non-constant growth DCF model, in which IIEC claims he also respects the accepted limitations on growth rate inputs and reflects investors' rational expectations of future growth.

According to IIEC, Mr. Hevert suggests that growth can be produced in ways other than reinvestment of earnings or growing book value by selling additional stock at market prices above book value – though IIEC says he has not identified any such alternative earnings growth source nor explained how this unidentified growth source can be used as a valid sustainable long-term growth rate. IIEC finds it surprising that Mr. Hevert quarrels with use of internal growth as a limiting factor on sustainable growth rates, since he uses the Gordon Model, which uses the retention rate to determine a terminal stock price, as the basis for his multi-growth DCF model input.

IIEC says Mr. Gorman found Mr. Hevert's criticisms based on academic literature, reliance on an aberrant Commission determination that reflects the use of historical, instead of forward-looking inputs, and unpersuasive. IIEC claims his academic literature arguments are based on studies concerning real growth rates, not the distinct nominal growth rates required by the DCF model. IIEC says he also relies on a Commission decision using an unsustainable growth rate (a recent ComEd case). IIEC claims that decision is a departure from the Commission's long-standing approach. According to IIEC, the Commission has rejected a long-term sustainable growth rate derived from historical GDP growth data (like Mr. Hevert's) in several cases preceding that most recent ComEd case. IIEC asserts that the Commission has more consistently rejected historical GDP growth rate estimates as reflective of investor expectations for future growth and it has viewed published GDP growth projections as a reasonable proxy for the ceiling on growth rates for a utility. IIEC also claims that by relying on historical data, Mr. Hevert fails to reflect the consensus market participants' outlooks of future long-term GDP growth and overstates the DCF return estimate.

In his analysis, Mr. Hevert relied on a growth rate (based on historical data) of 5.72% as a long-term sustainable growth in the third stage of his multi-stage growth DCF study. IIEC finds that input excessive and flawed, and recommends that Mr. Hevert's multi-stage growth DCF analysis be disregarded. IIEC claims that in his analysis, Mr. Hevert went through the motions of observing the accepted GDP ceiling on long-term sustainable growth, by calculating a GDP growth estimate that he used as his long-term growth rate input. IIEC says his calculation combines a real GDP growth rate outlook with a CPI inflation outlook that is not based on GDP.

According to IIEC, this CPI inflation is not based on GDP but rather is based on a subgroup of the U.S. economy that reflects a consumer basket of goods. IIEC asserts that the CPI, unlike the GDP price deflator, is far more heavily weighted with personal consumption items rather than a measure of the U.S. economy. IIEC claims the CPI is heavily weighted with medical costs and that the GDP price deflator includes medical costs but not to the same extent as the CPI. IIEC argues that the CPI inflation factor is not designed to reflect the entire U.S. economy. In order to accurately measure the GDP nominal growth, IIEC contends one must combine the GDP real return with a projection of the GDP price inflation. IIEC says the U.S. Department of Commerce uses the GDP price deflator as the inflation measure for the entire U.S. economy and claims because Mr. Hevert did not use the GDP price deflator, he did not accurately measure nominal GDP growth.

In its Reply Brief, IIEC claims that both it and Staff constructed their DCF and CAPM studies in this case in a manner similar to what they did in AIC's last rate case. IIEC says the Commission accepted those analyses and used them in its cost of equity determination in that case. IIEC states that AIC's witness, Mr. Hevert, used variations of the DCF and CAPM models that are inconsistent with those models traditionally found to be reliable by the Commission and by other utility regulators.

IIEC also alleges that AIC did not make any substantive argument responding to the challenges to the growth rate used by its witness, Mr. Hevert. IIEC claims AIC asks the Commission to adopt the very high growth rate used in a recent ComEd case, irrespective of what the record in this case shows for this utility.

According to IIEC, the Commission does not make findings on the precise numbers used as cost of equity model inputs as a matter of policy that it carries from case to case. IIEC insists that the law requires that the Commission make findings in each case on the basis of the record before it, not on the basis of "what the other guy got."

IIEC also complains that AIC's Initial Brief dismisses IIEC's cost of equity evidence in only two sentences. In IIEC's view, such subjective characterizations are not persuasive. IIEC also alleges that AIC's Initial Brief incorrectly summarizes its own testimony. IIEC says Mr. Hevert criticized IIEC's sustainable growth DCF, not its multi-stage growth DCF model, asserting concern with the dividend payout ratios. IIEC states that AIC's only argument addressing Mr. Gorman's multi-stage growth DCF model concerned the final stage sustainable growth rate.

According to IIEC, AIC's complaint that Mr. Gorman's constant growth DCF model analysis is not relevant -- if accepted by the Commission -- would exclude Mr. Gorman's highest DCF result from his calculation of the results' average, lowering the return estimated by Mr. Gorman's DCF analyses.

IIEC contends that AIC does not address the relative, substantive merits of the approaches taken by the expert witnesses on the sustainable growth rate in this case. IIEC believes such a legal and factual analysis is what the Act requires to support a record-based cost of equity determination. But instead of attempting to meet the substantive challenges to its outlier growth rate input, IIEC asserts that AIC's Initial Brief looks over the fence at the growth rate ComEd used in its last case and asks the Commission for the same, irrespective of the record before the Commission.

IIEC indicates that AIC asserts that the Commission will appear arbitrary instead of reliable if it does not adopt that element of the record in another case. IIEC complains that AIC has selected as the standard of Commission behavior a single case, which is itself a departure from the Commission's more consistent approach in prior cases, where reasonable, sustainable growth rates for the final stage of the DCF model were required.

In IIEC's view, AIC's suggestion of arbitrariness is not applicable to the growth rate used as the terminal growth rate of IIEC's multi-stage DCF model. IIEC says the long-standing practice of the Commission is to rely on consensus analysts' growth rate projections, including GDP growth rates, for use as long-term steady-state growth rate inputs to a multi-growth DCF model. IIEC claims the Commission departed from this long-standing practice in the 2010 ComEd rate case. IIEC claims that if there is arbitrariness, it is the ComEd decision that is "arbitrary." IIEC argues that the position of

Staff, IIEC, and AG-CUB that proper growth rates must be sustainable over the infinite period of the DCF model tracks the traditional approach of Commission decisions.

IIEC also contends that AIC does not (or refuses to) recognize that the growth rate finding in the ComEd rate case had to be a factual determination, based on the record in that case. IIEC claims there is no Commission policy that national GDP growth should be (or would be considered to be) 6% in every case, for all time. IIEC believes such a decision -- even if the Commission had intended that result -- would be unlawful.

IIEC argues that the record in this case does not support AIC's excessive growth rate. According to IIEC, the record in this case provides substantive reasons to maintain the Commission's long-standing practice of relying on consensus analysts' projections of future GDP growth for this terminal stage DCF growth estimate and looking to the GDP as a ceiling on sustainable growth rates. IIEC says AIC relied on historical real growth, with projected inflation rates. IIEC believes Mr. Hevert relied on unrealistic expectations that future real GDP growth will be comparable to historical real GDP growth, even though the U.S. now competes in a worldwide economy that presents far greater competition for commerce than the U.S. economy faced historically.

b. CAPM

IIEC says Mr. Gorman's CAPM analysis was the fourth estimation model process he employed to estimate AIC's market required cost of equity. IIEC indicates that he applied the CAPM to the same proxy group of publicly traded utilities he used with his DCF models. IIEC reports that Mr. Gorman's CAPM estimate establishes the upper end of his range of estimates.

Mr. Gorman used forecasted 30-year Treasury bond yields as his risk-free rate. IIEC claims that because this input includes some effects of inflation, it can produce an overstated estimate for companies with betas less than one. IIEC says his beta input was derived from published Value Line beta estimates for the proxy group firms. For the market risk premium input, Mr. Gorman derived two estimates, one forward-looking and the other based on a long-term historical average. According to IIEC, the forward-looking estimate was derived by estimating the expected return on the market, as represented by the S&P 500 (as the sum of expected inflation and historical real return on the market), then subtracting the risk-free rate from this estimate. IIEC indicates the historical estimate was derived using Morningstar's published estimates of the historical arithmetic average real market return (8.7%), to which he added a current consensus analysts' inflation projection (2.3%). IIEC says these estimates (summed) yield an expected market return of 11.20%, and subtracting his 5.2% risk-free rate estimate produce a market risk premium of 6.00%.

IIEC expresses concern about the beta estimates used by Mr. Hevert. IIEC believes one of the two beta estimates he uses is over-stated and unreasonable. IIEC says for his gas proxy groups, Mr. Hevert uses an average of the published beta estimates by Value Line and Bloomberg from historical beta and a (higher) current beta that Mr. Hevert computed from a small set of recent data. IIEC claims the beta estimates computed from 12 months of data are based on substantially fewer observations than the published beta estimates, making that statistical derivation of beta much less reliable, since it will reflect short-term movement that will smooth over a longer period.

IIEC also asserts that such short-term data are more consonant with the information relied on by short-term speculators than by investors willing to fund long-term investments. IIEC also believes Mr. Hevert's concern that recent volatility would not be captured in published betas appears unfounded. IIEC claims the data periods used for those beta estimates include the periods of instability Mr. Hevert cites, and the estimates themselves are consistent with current beta estimates.

IIEC also believes that Mr. Hevert's market risk premium estimates (9.21% and 8.09%) are inflated. IIEC says Mr. Hevert's first market premium is a DCF-derived estimate that is based on a market return of more than 13.5%, which incorporates a growth rate of more than 11.5%, which IIEC says is more than twice the long-term GDP growth outlook. IIEC insists that is a growth rate estimate too high to be a rational, sustainable growth rate estimate, and produces results that are not a reliable basis for the Commission's determination. IIEC asserts that Mr. Hevert's beta and market risk premium estimate methods have never been adopted by a regulatory commission. In IIEC's view his experiment should not be the basis for setting rates for AIC ratepayers.

In its Reply Brief, IIEC states that AIC claims IIEC witness Gorman employs an inappropriate market risk premium and improperly relies on Value Line as his sole source of beta coefficients. IIEC says AIC offers no further substantive argument regarding IIEC's positions and testimony and that there are only bare references to the testimony of its witness, Mr. Hevert.

IIEC says Mr. Hevert's criticism of Mr. Gorman's use of published beta estimates is based entirely on his opinion that betas derived from a shorter data period should be given more weight. IIEC indicates that he uses the higher beta he calculated specifically for this litigation from a shorter period of data. IIEC claims that elsewhere AIC has criticized the use of brief periods of data as susceptible to volatile market movements that may not reflect the general market trends. IIEC complains that AIC embraces the higher betas derived from such data.

According to IIEC, based on his flawed methodologies and other changes that do not reflect utility stock and bond investment risk, Mr. Hevert made substantial inappropriate adjustments to the measured utility beta estimates and the market risk premium estimates used in his analysis. IIEC urges the Commission to reject Mr. Hevert's CAPM return estimates.

c. Other Models

IIEC indicates that because the Commission has consistently declined to consider the results of risk premium cost of equity analyses, Mr. Gorman did not perform one. Only Mr. Hevert performed such an analysis, using a risk premium derived from reported returns approved by other commission for other utilities. IIEC contends that Mr. Hevert has not provided any information that shows the risk premium approach to be superior or to warrant a change in the Commission's historical position.

IIEC says Mr. Hevert constructs a risk premium return on an equity estimate based on the premise that equity risk premiums are inversely related to the interest rates. IIEC believes that Mr. Hevert's simplistic inverse relationship premise is not supported by relevant academic research and that the results of this exercise are unreliable and should be discarded.

d. Adjustments to ROE

IIEC did not propose an adjustment to recognize the effect having an uncollectibles rider has on AIC's level of risk. However, IIEC believes that regulatory mechanisms that increase AIC's assurance of full cost recovery (such as Rider GUA), will lower AIC's operating risk. IIEC says the appropriateness of an adjustment would depend on the extent to which the risk reduction attributes of such regulatory mechanisms are fully reflected in the risk factors considered by credit rating analysts and the selection of the proxy group identified firms of comparable risk.

e. Flotation Costs

IIEC indicates that Mr. Hevert developed a flotation cost recovery adjustment that would increase AIC's return on equity by 14 basis points. IIEC says Mr. Hevert did not make an adjustment to his recommended cost of equity; instead, he stated that he considered flotation costs in determining where within his range of estimates AIC's return on equity should fall. IIEC claims the precise effect of Mr. Hevert's flotation adjustment on his cost of equity recommendation is unknown. In IIEC's view, approval or disapproval of his adjustment thus would seem to be a moot exercise for the Commission.

According to IIEC, if the Commission decides to address this issue, it must do so in hypothetical terms and without common ground for the various arguments presented. IIEC says the Commission has not regularly included flotation costs in its determination of a utility's cost of equity.

In response to Mr. Gorman's and Ms. Freetly's observations that AIC had not shown that it had actually incurred flotation costs and the amount thereof, Mr. Hevert abandoned his estimate based on equity issuances by Ameren and proxy group firms for an estimate based on Ameren costs. IIEC asserts that AIC, the utility, has not incurred, and indeed cannot incur flotation costs. IIEC complains that Mr. Hevert simply assumes that any identified amount has not been recovered. Citing Section 9-230 of the Act, IIEC also argues that there is no basis on which the Commission could approve recovery of estimated costs of incurred by AIC's unregulated parent firm.

Citing Staff witness Freetly, IIEC says historical flotation costs (even when actually incurred by a utility) may have been recovered as expenses. IIEC says Mr. Hevert does not even claim to know the actual historical treatment of even the non-utility costs he offers as the basis for his adjustment. IIEC states that AIC asks the Commission to use the utility's unfounded conclusion about past costs for another company as data for its future test year ratemaking and to grant the utility continuing, increased future earnings based on the alleged past costs. IIEC says the requested mechanism for this grant is a perpetual return on equity adjustment, as proposed by Mr. Hevert. IIEC believes AIC's proposal respecting flotation costs should be rejected.

4. GCI Position

GCI urges the Commission not to be swayed by the rhetorical excesses presented by AIC's witnesses in their rebuttal testimony. GCI believes that AIC fundamentally asks that the Commission abandon its past practice of relying on objective market data and financial models by emphasizing subjectivity and fear over objective analysis. Of the expert recommendations in this record, GCI notes that the one offered by Mr. Hevert (10.75% for AIC's gas operations) was by far the highest -- some 150 basis points above the high end of Mr. Gorman's recommended return 9.25%. GCI also notes that Staff witness Freetly recommends even lower returns for AIC, 8.9% for gas operations. GCI adds that Mr. Gorman and Ms. Freetly recommended ROEs at the top of the range of reasonable results that Mr. Thomas identified.

GCI asserts that Mr. Thomas' analysis fits right within the range identified by Staff and IIEC, with a return of 9.02% for AIC's gas operations. GCI believes that risk premiums of 6-7% are excessive in relation to the riskiness of the public utility business. GCI also asserts that application of the DCF model requires growth rates that are reasonable for the low-growth utility industry. GCI believes that application of the CAPM must be done in a manner consistent with the way the model is used by financial professionals outside the rate setting process. To limit the scope of the cost of equity debate in this case, GCI says Mr. Thomas narrowed the range of issues addressed in his analysis. Instead of conducting a completely separate analysis, GCI indicates Mr. Thomas reviewed Mr. Hevert's analyses and data, and suggested corrections based on prior Commission Orders, the governing legal precedents and the evidence presented by AIC.

GCI says Mr. Thomas corrected Mr. Hevert's DCF analyses to set the long-term sustainable growth rate in a manner that is consistent with the Commission's Final Order in the Company's last rate case, Docket Nos. 09-0306 et al. (Cons.). GCI states that he corrected Mr. Hevert's DCF analysis to remove his inappropriate and unsupported assumption that dividend payout ratios will increase. Next, GCI says he corrected the beta estimates used in the CAPM to reflect observations from more than one financial reporting source. According to GCI, Mr. Thomas corrected the CAPM market risk premium to reflect a balance of historic risk premiums and projections presented by Mr. Hevert. Finally, GCI says Mr. Thomas examined Mr. Hevert's additional proposed analyses which were previously rejected by the Commission, including the "Bond Yield Plus" risk premium analysis and proposed flotation cost adjustment.

GCI indicates the Commission has typically relied on averages of the DCF and CAPM, something that GCI believes is appropriate to do again here with the DCF results marking the upper boundary of reasonable returns. Using this framework, GCI says Mr. Thomas concluded that for the AIC Gas operations, reasonable results range from 7.41% to 9.02%, with an average of 8.22%.

According to GCI, AIC has not presented any objective basis for the Commission to adopt its recommendation. GCI says AIC warns that the Commission should be concerned about Wall Street's reaction if its determination, no matter how well-founded, does not align with the decisions of other state commissions. GCI believes AIC would rather the Commission focus on investor expectations than deriving AIC's real cost of capital from objective market data.

GCI says three different AIC witnesses try to focus the Commission away from the models it has always relied on and towards credit rating agency expectations. GCI states that in Docket No. 10-0138, the Commission questioned whether appealing to investors is something that is within the Commission's purview or even within its statutory jurisdiction. GCI asserts this is even before the record evidence in this case that credit rating agencies have been widely criticized for their investment-grade ratings of subprime mortgage backed securities, which are seen as the major issue precipitating the economic crisis of 2008. According to GCI, there is no evidence that AIC's credit ratings have been negatively impacted when the Commission awarded the utility significantly less than it requested. GCI says this action did not negatively impact the utilities' credit ratings.

AIC characterizes the recommendations of Staff, IIEC and GCI as unreasonable compared to other electric and natural gas utility authorized returns on equity. GCI believes such comparisons are not only irrelevant but of dubious value, since AIC provides no investigation of the comparability of risk for each of the companies and no detail on any regulatory framework within which those companies operate. In GCI's view, the fact that the Commission does not compare favorably to some other state regulatory commissions in similar positions is merely demonstrative of the Commission's efforts on behalf of the consuming public to ensure that all costs that are passed on to the general rate-paying public are reasonable.

GCI believes the Commission should base its determination of a fair return on the relative riskiness of the regulated company. According to GCI, AIC's attempts to persuade the Commission to ignore the objective approaches of Staff, IIEC and GCI should be rejected. GCI asserts that the foundation of the Commission's decision is market data, appropriate financial models based on those data, and bedrock economic/financial principles. GCI says the Commission has been, for a long period of time, dedicated to ensuring that only reasonable and legally-recognizable costs are passed on to ratepayers.

In its Reply Brief, GCI says that AIC accuses Staff and other parties of low-balling their ROE recommendations. GCI alleges this is not surprising, asserting that AIC has high-balled its own ROE recommendations to the point of being a lone outlier, even the lowest end of its range is a full 90 basis points above any other ROE recommendation in the case. GCI claims AIC invokes scare tactics in an attempt to intimidate the Commission into submitting to its over-inflated requested ROE by claiming that keeping AIC's ROE right where it is, is akin to daredevil, tightrope-walking regulation that will result in AIC being on the verge of collapse. GCI states that AIC further claims that a Commission decision based on Staff, IIEC and GCI recommendations would be an arbitrary departure from the Commission's recent practice and that such arbitrariness and randomness must be avoided. In GCI's view, such rhetoric should be disregarded for what it is: a ploy to distract the Commission from its required review of the evidence in this proceeding, in line with the controlling law and Commission-developed policies, demonstrating that an ROE in the range of 7.41% to 9.02% would be the only supportable, justifiable and appropriate ROE.

GCI agrees with AIC that the Commission should develop returns on equity in a coherent, consistent manner. GCI states that AIC suggests the Commission will recognize arbitrariness by looking not to the instant record or to an appellate court, but to statements made by credit rating agencies. GCI claims the Commission has previously rejected such an analysis. Citing Docket No.10-0138, GCI says the Commission's task is to determine the market required return on equity investments in the Companies -- not the information available to investors. GCI claims the market required return is the result of the interaction of that information available to investors, the financial environment, how investors react to available information, and all other factors that influence the market required return. GCI contends that how investors subjectively felt or what they thought, though interesting to contemplate, is not the task at hand.

GCI complains that AIC does not explain how its proposed ROEs conform with past Commission decisions other than to simply dismiss the testimony of Mr. Thomas and IIEC witness Gorman. GCI says the criticisms of both witnesses with respect to Mr. Hevert's DCF models are not addressed. GCI indicates that AIC presents detailed criticism of the testimony of Staff witness Freetly regarding the use of spot prices and growth rates in both the DCF and CAPM models as well as the appropriate beta coefficient in the CAPM model.

According to GCI, the Commission has typically relied on averages of the DCF and CAPM, and GCI believes it would be appropriate to do so here, with the caveat that the DCF average should represent the upper boundary of reasonable results.

a. DCF

GCI states that Mr. Hevert relies on a multi-stage DCF model, which assumes that growth in the short-term (typically years 1 to 5) will transition (in years 5 to 10) to long-term sustainable growth rate (typically beginning in year 10). Through his applications of DCF financial models to selected financial data, GCI indicates that Mr. Hevert derives DCF estimates of AIC's cost of capital that range from 9.51% to 11.24% for AIC's gas operations. While the Commission has previously accepted multi-stage DCF models using analysts' growth forecasts in the short-term, transitioning to the long-term growth rate in GDP over time, GCI believes the Commission in this case must correct the long-term growth rate that Mr. Hevert used in his analysis to conform with prior practice, and to be consistent with current implied growth rates in GDP. GCI suggests the Commission must also remove the inappropriate and unsupported adjustment that Mr. Hevert made to AIC's dividend payout ratio. GCI states that Mr. Thomas used the same sample groups and analysis used by Mr. Hevert, which he corrected by using an appropriate long-term growth rate of 4.825% and by removing the assumption that dividend payout ratios will revert to anything other than their current levels. GCI says these corrections result in DCF Results for the Gas Sample that range from 8.80% to 9.02%.

GCI states that the growth component of a DCF model represents the sustainable growth that investors expect in their investment due to increases in a company's earnings. According to GCI, the rate used has to be consistent with, and supported by, the economic conditions and dividend payout policies expected to occur. Since both Mr. Thomas and Mr. Hevert relied on a multi-stage DCF model in their analyses, GCI says the growth rate is assumed to change over time. GCI asserts that empirical reviews of analyst growth rates previously relied on by the Commission show a pattern of upwardly biased analyst growth rate forecasts in comparison to the actual requirements of investors reflected in stock prices. GCI claims that several empirical studies have documented optimistic bias in analysts' earnings forecasts, indicating that the DCF model must be adjusted downward. GCI argues that when looking beyond two years in the future, the best forecast of earnings growth is the historical average growth rate.

GCI believes Mr. Hevert's long-term sustainable growth rate is overstated. GCI says he relies on a long-term growth rate of 5.72% based on real chain weighted GDP growth of 3.28% and a 2.37% estimate of inflation based on Blue Chip Financial Forecasts and the EIA's projected compound annual CPI growth rate. GCI says Mr. Thomas analyzed the consensus forecast published in the Blue Chip Economic Indicators and found that it varied significantly over time. GCI states that on February 10, 2011, the real GDP forecast was 3.2% in 2011 (up from the 2.5% forecast made in December 2010) and 3.3% in 2012. GCI says adding real GDP growth to inflation, as measured by the CPI, implies growth of 5.1% and 5.3% being forecasted in February, 2011 - a significant increase from the 4% being forecast in December 2010.

GCI contends that growth returns should reflect unbiased growth estimates as indicated by market prices since utility companies cannot reasonably be expected to grow faster than the overall economy. GCI urges the Commission to continue to use the long-term growth in GDP as the upper boundary of sustainable growth for utility companies. GCI states that using the Commission's traditionally accepted methodologies, Mr. Thomas calculated a long-term sustainable growth rate of approximately 4.825%, well within the range of all other experts in this proceeding, except AIC's.

b. CAPM

According to GCI, even though the CAPM is widely used and relatively simple, there are several well-known problems with both the theory and the practical application of the model. GCI claims economists have studied the relationship between actual market behavior and the CAPM model for a number of years, in particular, how to evaluate the risk of a company as compared to that of the marketplace overall. GCI suggests the CAPM should be used with its limitations understood and that it is best employed as a check on the results of a DCF model.

GCI indicates that the Commission has traditionally accepted beta coefficients that are adjusted for mean reversion, or a supposed tendency to revert to the market mean (1.0), as valid CAPM inputs. GCI says this is the method commonly relied on by Value Line, one source used by Mr. Hevert in his analysis, but this method also means that the Value Line beta (and Mr. Hevert's CAPM analysis) is upwardly biased in comparison to a broader sample of the published estimates of that critical input. GCI says Mr. Hevert averages this Value Line beta with one from Bloomberg for the proxy group companies, and calculates short-term betas, resulting in a range from .703 to .862 for the gas sample.

GCI asserts that comparing Mr. Hevert's results to the published betas demonstrates his upwards bias, and highlights the problem with relying on few sources. GCI says betas from different sources exhibit wide variability. To be complete, GCI suggests the Commission should consider a range of betas reported by the various reputable financial data reporting sites so the Commission can avoid unintended bias in various estimates used in a cost of equity determination.

GCI states that the EMRP represents the premium, above the risk-free rate, that investors expect when they take on the risk of an investment in the market portfolio, or the universe of potential investment opportunities available to investors. Mr. Hevert uses EMRP values ranging from 8.09% to 9.36% in his analysis, which are estimates derived from academic studies of market performance or using EMRP estimates calculated for particular situations.

According to GCI, the EMRP is the premier question relating to the cost of capital, for theorists and practitioners alike. GCI contends the overwhelming conclusion from current research on the EMRP is that the return expected by investors and appropriate for use in the CAPM is far lower than returns calculated from selective samples of historical information. GCI says historical estimates found in most textbooks, which often report numbers near 8%, are too high for valuation purposes because they compare the market risk premium versus short-term bonds, use only 75 years of data, and are biased by the historical strength of the U.S. market. GCI suggests the general consensus is that the aggregate stock market exhibits negative autocorrelation, resulting in an arithmetic mean that is upwardly biased.

GCI suggests the Commission should consider an EMRP analysis that relies on a reasonable range of EMRPs, which the academic research indicates is within the range of 3.0 to 5.0%, with some research indicating that the actual EMRP is much lower. GCI says Mr. Thomas calculated two different CAPMs using the end points of a spectrum of EMRP estimates. GCI adds that at one end of the spectrum is the historic EMRP of 6.70%, as reported in Mr. Hevert's work papers but not used in his testimony, and at the other end is the 9.36% estimate calculated by Mr. Hevert, which is clearly outside the estimates found in the academic research.

GCI says the CAPM model is very sensitive to changes in the selected beta – that is, small changes in the beta coefficient produce large changes in the overall CAPM result. GCI indicates Mr. Thomas adjusted Mr. Hevert's CAPM analyses with a variety of reported betas and expanded the EMRP using inputs identified in Mr. Hevert's testimony. If the Commission believes that the CAPM is a valuable tool, GCI suggests it should use these results to find that the cost of equity for AIC should be at the lower end of any range of valid estimates.

c. Other Models

GCI states that the risk premium method that Mr. Hevert uses is another measure of capital costs based on the same principle of evaluating the relative riskiness of a security to the market. GCI says the analysis he presents is similar to other risk premium analyses presented to the Commission in past cases. Citing Docket Nos. 07-0241/07-0242 (Cons.), GCI says the Commission previously rejected this type of analysis.

GCI says when AIC and IIEC last presented this approach to the Commission it was rejected, with the Commission concluding those analyses were no reason to deviate from past practice wherein it has relied on the DCF and CAPM models to estimate cost of common equity. Because of the similarities between Mr. Hevert's analysis and the past analyses rejected by the Commission, GCI urges the Commission to reject the proposed risk premium method once again.

d. Flotation Costs

Mr. Hevert also proposes that the Commission adopt a 13 basis point adjustment to recognize flotation costs for AIC's gas operations. GCI says flotation costs are the costs the company incurs when it issues securities. GCI adds that Mr. Hevert's proposal to include adjustments to recover flotation costs is based upon estimates of other utilities' flotation costs, not in relation to any specific costs incurred by Ameren. Citing Docket Nos. 07-0241/07-0242 (Cons.), GCI contends this is an inappropriate and unnecessary adjustment that has been previously rejected by the Commission. GCI urges the Commission to reach the same conclusion here, both because AIC has not proven that the costs are actually unrecovered, and because it is fundamentally inappropriate to recover costs that AIC has not actually incurred.

5. IBEW Position

IBEW contends that AIC must be allowed to earn a reasonable ROR. IBEW says AIC still faces a rising regulatory risk. IBEW believes recent rate case outcomes in Illinois have caused concern to ratings agencies, such as Moody's, about the political and regulatory risks for companies in the state and the outcome of future rate cases. IBEW claims a stable credit outlook is contingent on future rate case outcomes being more supportive of credit quality. IBEW suggests the recommended returns of some parties could potentially lower AIC's credit ratings. IBEW says the returns recommended by Staff, GCI, and IIEC could make it difficult for AIC to maintain its financial integrity, causing AIC to reduce staff and contractors. These actions would be particularly harmful to IBEW and its members in these difficult economic times.

IBEW also says while the Commission is not bound by other states' ROE awards, these are considered by investors and should be considered when evaluating the alternative ROE recommendations in this case.

a. DCF

According to IBEW, all ROE witnesses in this proceeding place significant weight on the results of the multi-stage DCF model. However, one main point of disagreement between the ROE witnesses in this case is the differences in the terminal growth rate assumptions (because the terminal stage of that model tends to represent a significant portion of the analytical results). IBEW says the Commission recently found a 6.00% long-term growth estimate to be reasonable in ComEd's last rate case. IBEW agrees with AIC witness Hevert that this should be a reference point when evaluating terminal growth rate assumptions within various ROE witness recommendations.

Regarding the multi-stage DCF model, IBEW suggests the principal analytical issue is whether long-term growth rates of 4.80% to 4.90% are more plausible than the 5.64% growth rate included in AIC's updated analyses, or the 6.00% growth rate recently relied upon by the Commission. IBEW supports AIC's recommendations that the Commission find the long-term growth rates assumed by the other ROE witnesses unduly low, and therefore produce ROE estimates that are well below AIC's cost of equity.

b. Adjustments to ROE

IBEW notes that Staff proposes to reduce AIC's ROE by 16.25 basis points to reflect the effect of the uncollectibles rider on investor expectations. IBEW says while Staff purports to "calculate" this risk by predicting the effect of the rider on AIC's rating from Moody's, IBEW thinks there is no empirical basis for Staff's assertion that the rider reduces risk. IBEW agrees with AIC that Staff's ROE deduction is inappropriate, even if such a risk existed. IBEW says since the passage of legislation in July 2009, ComEd, Peoples, North Shore, and Nicor all received Commission Orders authorizing their respective bad debt riders on February 2, 2010. IBEW thinks such a discrepancy flies in the face of conventional wisdom. IBEW says this is neither consistent nor fair public policy.

6. Commission Conclusion

As previously noted, four parties presented the testimony of expert witnesses addressing AIC's cost of common equity. AIC offered the testimony of Mr. Hevert, Staff offered the testimony of Ms. Freetly, IIEC offered the testimony of Mr. Gorman, and GCI offered the testimony of Mr. Thomas. The table below summarizes the recommendations of those parties offering testimony on cost of common equity.

<u>Summary of Recommendations</u>

AIC	10.75%
Staff	8.90%
IIEC	9.25%
GCI	8.22%

Before the Commission turns to the details of the parties' return on equity estimates, it is apparent some parties want the Commission to abandon or deviate from certain past practices in light of new evidence or circumstances. Other parties argue that the Commission is strictly bound by decisions it has made in previous proceedings, for AIC or other utilities. The Commission must balance competing interests in evaluating such proposals. While the Commission does not wish to totally ignore its past practices, which appear to have served utilities and ratepayers for many years, the suggestion that the Commission is strictly bound to follow decisions in previous proceedings with different evidentiary records is simply wrong. Nor does the Commission wish to engage in cost of equity estimation in a manner that might be viewed as random or arbitrary, but at the same time the Commission recognizes that it must consider the possibility that new evidence or research has been developed that should cause the Commission to deviate from past practices. While recognizing that due to the competing interests present, it is not possible to satisfy all parties, the Commission will undertake to reach well-reasoned conclusions that are based on the record and consistent with previous Commission decisions, to the extent possible.

Also as discussed above, AIC's briefs focused on what it considered to be the three most significant differences among the parties. Those issues are the third stage growth rate used in the multi-stage DCF analysis, the use of spot prices rather than average prices, and the proposal to reduce ROE because AIC uses the uncollectibles expense rider. It appears to the Commission that AIC is correct that these three issues are significant and will, therefore, be the focus of the Commission's decision. The Commission will, nevertheless, address other contested issues to the extent necessary to determine the reasonable cost of equity for establishing rates in this proceeding.

a. DCF

As the Commission understands it, AIC witness Hevert relied upon a multi-stage DCF analysis, which he updated in rebuttal and surrebuttal testimony. GCI witness Thomas relied upon Mr. Hevert's DCF model with modified inputs. Staff witness Freetly also relied upon a multi-stage DCF analysis. IIEC witness Gorman relied upon a constant growth DCF analysis with analysts' growth rates, a constant-sustainable growth rate DCF analysis, and a multi-stage DCF analysis, giving equal weight to all three DCF estimates.

Historically speaking, the Commission has relied heavily on the constant growth DCF model; however, in recent years the Commission has tended to favor the multi-stage DCF model over the constant growth model due to concerns about the sustainability of analysts' growth rate estimates. Even Mr. Gorman suggests that his analysts' growth rates may not be sustainable for his electric sample. See IIEC Ex. 3.0 at 32. The Commission would not be surprised if circumstances change such that, at some point in time, it would be appropriate to rely on the constant growth DCF model. Of the four witnesses, only Mr. Gorman suggests that time has arrived. The Commission, however, is not convinced he is correct on this point. Instead, the testimony of the other three witnesses, particularly Ms. Freetly who thoroughly explained her rationale for choosing the multi-stage DCF model over the constant growth DCF model, demonstrates that for this proceeding, the constant growth DCF model is not appropriate for purposes of this proceeding. See Staff Ex. 8.0 at 5-6.

It appears to the Commission that Mr. Gorman may have decided to rely, in part, on a constant-sustainable growth DCF analysis because of concerns about the sustainability of the analysts' growth rates in his constant growth DCF analysis. To the extent this is true, it supports the Commission's view that relying on Mr. Gorman's constant growth DCF analysis is questionable. Mr. Gorman developed the sustainable growth rate inputs based upon internal growth plus external growth factors that Mr. Gorman suggests can be sustained indefinitely by companies. IIEC Ex. 3.0 at 26.

As an initial matter, the Commission notes that it generally has not relied upon a constant-sustainable growth DCF model for establishing the cost of common equity in rate cases. In fact, the Commission declined to rely on AIC witness McShane's and Mr. Gorman's sustainable growth DCF model in AIC's last rate case, Docket Nos. 09-0306 et al. (Cons.). See Order (April 29, 2010) at 216. In previous cases, the Commission has expressed concern that sustainable growth estimates are problematic in that they rely upon a proxy for ROE as an input when estimating the investor required return. The Commission is concerned that such internal growth rates are not reliable enough for use in directly estimating a utility's cost of common equity. Mr. Gorman has not provided any analysis or arguments that convince the Commission it should change its view on the reliability of internal growth rates. In fact, Mr. Gorman expressed "strong concerns" about the constant-sustainable growth DCF for the Gas Proxy Group. See IIEC Ex. 3.0 at 28-29. The Commission concludes that there is not a sufficient basis for relying on the constant-sustainable growth DCF in establishing the cost of common equity for AIC in this proceeding. Accordingly, the Commission concludes that it is appropriate to rely upon the multi-stage DCF model in determining AIC's cost of common equity.

One of the most important inputs into the multi-stage DCF model, and most contested in this proceeding, is the steady-state growth rate. AIC witness Hevert calculated a steady-state growth rate of 5.66% and, relying heavily on the Commission's decision in Docket No. 10-0467, AIC suggests a steady-state growth rate of 6.00% is appropriate in the current proceeding. To develop his steady-state growth rate, Mr. Hevert summed his estimate of long-term inflation, 2.31%, and his estimate of long-term nominal GDP growth, 3.3%. Mr. Hevert's long-term inflation estimate is based on projections of growth in CPI while his estimate of long-term nominal GDP is based on long-term historical growth in GDP (e.g., 1929 through 2009).

Staff witness Freetly's estimate of the steady-state growth rate is 4.80%. Ms. Freetly's estimate of inflation, 2.50%, is derived from the difference in yields on U.S. Treasury bonds. Her estimate of the real long-term growth is based upon forecasted growth in GDP from EIA and Global Insight.

IIEC witness Gorman's estimate of the steady-state growth rate is 4.9%. Mr. Gorman relied upon forecasts of nominal GDP growth as well as forecasts of real GDP growth and forecasts of inflation to derive his estimate of the steady-state growth rate.

GCI witness Thomas says that in AIC's last rate case, the Commission relied upon the implied 20-year forward U.S. Treasury rate in 10 years and Blue Chip economic forecasts of nominal GDP growth. Mr. Thomas estimates the steady-state growth rate to be 4.825%. His estimate is based upon the implied 20-year forward U.S. Treasury rate in 10 years. He declined to rely upon the Blue Chip forecasts because he believes they are too volatile.

It is obvious to the Commission that the estimates of the steady-state growth rate provided by Ms. Freetly, Mr. Gorman, and Mr. Thomas are relatively consistent, particularly when compared to Mr. Hevert's estimate. The three similar estimates share the characteristic that each relies on forward-looking data while Mr. Hevert's estimate relies, in part, on long-term historical growth in GDP. The record demonstrates that the primary criticism of Mr. Hevert's steady-state growth rate is his reliance on historical growth in GDP. In Docket Nos. 09-0306 et al. (Cons.), the Commission found Ms.

McShane's over-reliance on historical data in the development of the steady-state growth rate to be problematic. See Order (April 29, 2010) at 215-216. It appears to the Commission that Mr. Hevert's steady-state growth rate was developed in a manner similar to Ms. McShane's. However, as previously noted, each evidentiary record must stand on its own merits and the Commission does not find this sufficiently problematic in this proceeding to dismiss the use of the model in its entirety.

Also at issue in the DCF analyses is whether the Commission should rely upon spot stock prices or averages of historical stock prices. Mr. Hevert relied upon 30-day, 60-day, and 90-day average stock prices in his analyses. Mr. Thomas used the same stock prices as Mr. Hevert. Mr. Gorman relied upon the average weekly high and low stock prices over a 13-week period ended May 20, 2011. Ms. Freetly relied upon closing stock prices on June 3, 2011.

Generally speaking, over the last few decades the Commission has tended to rely upon spot stock prices. The Commission has typically expressed concern about the economic value of historical stock prices in establishing a forward-looking cost of common equity, as well as concerns about how to determine the appropriate period over which to average stock prices. In some recent cases, however, the Commission has also expressed concerns over spot stock prices, particularly in light of the volatility in the stock market. In this case, it appears that AIC has conceded that the issue of average versus spot stock prices is not a significant issue. Additionally, Ms. Freetly presented an analysis that is intended to demonstrate that her results do not depend heavily upon the particular day selected for the spot prices.

Having reviewed the evidence, the Commission finds that the analysis presented by Ms. Freetly mitigates some of the concerns the Commission has recently expressed regarding the use of spot prices. The Commission also concludes, however, that as AIC suggests, the timing of stock prices is not significant in this case. For purposes of estimating AIC's cost of common equity in this proceeding, the Commission concludes that it is appropriate to average the multi-stage DCF results of AIC, Staff, IIEC, and the GCI as shown in the table below:

DCF Results

AIC	10.53%
Staff	8.63%
IIEC	8.43%
GCI	8.90%
Average	**9.12%**

b. CAPM

There are three inputs to the CAPM: beta, the risk-free rate, and the EMRP. The other parties take issue with the beta estimates used by Mr. Hevert, particularly the beta estimates he calculated using a 12-month measurement period. The Commission has traditionally relied upon betas calculated with five years of data. While Mr. Hevert explained his rationale, the Commission is not convinced that betas calculated with twelve months of data are reliable or appropriate for use in establishing the cost of common equity.

Mr. Thomas relied upon variety of published betas in his CAPM analysis. In the past, Mr. Thomas has endorsed the use of unadjusted betas, which the Commission does not rely upon. In his direct testimony, Mr. Thomas specifically states that he included Value Line betas, which are adjusted. It is not entirely clear to the Commission, which if any of his other sources calculate adjusted betas. In contrast, the betas relied upon by Ms. Freetly (Value Line, Zacks, and calculated regression betas) as well as Mr. Gorman (Value Line betas) are clearly the types of betas the Commission has traditionally relied upon in implementing the CAPM.

For the risk-free rate, Mr. Hevert relied upon the current 30-day yield on 30-year Treasury bonds and the near-term projected 30-year Treasury yield. Mr. Gorman used the Blue Chip projected 30-year Treasury bond yield as a proxy for the risk-free rate. Ms. Freetly relied upon yields on 30-year Treasury bonds as a proxy for the risk-free rate. It appears that Mr. Thomas used Mr. Hevert's proxy for the risk-free rate. While measured in slightly different ways, there does not appear to be much disagreement over estimating the risk-free rate.

With regard to the EMRP, Mr. Thomas relied upon what he describes as estimates provided by academic research. The Commission has rejected Mr. Thomas' similar proposal for estimating the market risk premium in previous cases. See, e.g., Docket Nos. 07-0585 et al. (Cons.) Order at 213. Among other things, the Commission continues to believe that Mr. Thomas' suggestion does not seem to allow for the EMRP to change over time, which the Commission believes is necessary for any approach or method adopted.

Ms. Freetly developed an estimate of the EMRP by performing a DCF analysis on dividend paying firms that comprise the S&P 500. From that, she subtracted her estimate of the risk-free rate. Mr. Gorman expressed concern that Ms. Freetly's DCF analysis overstates the return on the market because he believes her growth rates are excessive.

Mr. Hevert developed two estimates of the EMRP; the first was calculated in a manner similar to Ms. Freetly, except that he included non-dividend paying companies in the S&P 500. Ms. Freetly asserts that by doing this, Mr. Hevert overstates the expected market return. Mr. Hevert's second estimate depended upon an assumption of a constant Sharp ratio. Ms. Freetly expressed concern that, among other things, this second analysis relied too heavily on historical data to estimate a forward-looking, expected market return.

Mr. Gorman derived a forward-looking EMRP and a long-term historical average estimate of the EMRP. For one EMRP estimate, Mr. Gorman estimated the long-term historical arithmetic average real return on the market, to which he added an expected inflation rate. It is not clear to the Commission, however, that using a long-term historical average real return constitutes a forward-looking real return. The Commission believes this approach relies too heavily on historical data. For his other estimate of the expected market return, Mr. Gorman performed a multi-stage growth DCF analysis on the S&P 500, which he averaged with Mr. Hevert's constant growth estimate of the return on the market. While it is not entirely clear from his testimony, it appears this is the very estimate which Ms. Freetly complained overstates the market return.

The Commission has serious concerns with the betas used by Mr. Hevert and Mr. Thomas. Similarly, the Commission has serious concerns with the EMRP estimates relied upon by Mr. Hevert and Mr. Thomas. Finally, the Commission has concerns with at least one, if not both, of the EMRP estimates used by Mr. Gorman. All things considered, the Commission finds that the only CAPM analysis that is clearly free of significant problems and which can be relied upon in this case is the one performed by Ms. Freetly.

c. Other

Mr. Hevert also performed a Treasury yield plus risk premium analysis. For this analysis, Mr. Hevert performed a regression analysis on his risk premium (authorized returns on equity less 30-year Treasury yields) and 30-year Treasury yields, using data from 1992 through 2010. Among the many problems the Commission finds with this approach is its reliance on utility authorized returns on equity throughout the U.S. Additionally, there is the concern about the heavy reliance on historical data and the difficulty in determining an appropriate historical period to rely upon. In summary, the Commission continues to question the validity of the bond yield plus risk premium approach. The Commission finds that for purposes of this proceeding, Mr. Hevert's analysis should not be relied upon.

d. Adjustments to ROE

Staff recommends that its cost of equity estimates be adjusted downward to reflect the reduction in risk associated with the use of uncollectibles riders. Staff recommends a downward adjustment of 16.25 basis points. AIC argues that the uncollectibles rider does not reduce risk relative to other utilities. AIC also asserts that it is not possible to calculate an adjustment with the precision that Staff has attempted. Finally, AIC complains that Staff's proposed adjustment is larger than the adjustment proposed for other utilities.

As an initial matter, the Commission finds that AIC's suggestion that the uncollectibles riders do not reduce risk is unpersuasive. Whether the uncollectibles riders also benefit ratepayers is irrelevant. All else equal, the presence of the uncollectibles riders reduces the variation in AIC's revenues and therefore, its risk. The Commission believes this is indisputable, notwithstanding the event study performed by

Mr. Hevert. Staff identified difficulties with performing an event study associated with regulatory actions generally and with Mr. Hevert's study specifically.

In the Commission's view, the only question is how to best quantify the impact of the uncollectibles riders in AIC's risk. While AIC takes issue with Ms. Freetly's quantification, it presents no real alternative. As a result, the Commission finds that the record supports Staff's recommendation to reduce AIC's cost of equity by 16.25 basis points to reflect the reduction in risk that the Commission finds results from the existence of the uncollectibles riders.

e. Flotation Costs

In his direct testimony, Mr. Hevert calculated a 14 basis point increase in the cost of common equity to reflect the impact of flotation costs. Ameren Ex. 3.7E shows that Mr. Hevert derived that 14 basis point adjustment by calculating the mean flotation cost of Ameren and ten other utilities. In his rebuttal testimony, Mr. Hevert suggests that his flotation cost estimate is based upon the last two common equity issuances by Ameren, and therefore AIC has met its burden of proof to demonstrate that it has incurred actual flotation costs that have not been recovered through rates. In his surrebuttal testimony, Mr. Hevert repeats a statement in his direct testimony that he is not proposing an upward adjustment to the cost of equity to reflect flotation costs. Instead, Mr. Hevert "considered" flotation costs when determining where within the range of results the ROE reasonably falls.

The Commission concludes that the record in this proceeding does not justify an upward adjustment to the cost of common equity to reflect flotation costs. In fact, it appears no witness has proposed such an adjustment. Staff correctly points out that the Commission is open to considering the impact of flotation costs on the authorized return on equity in certain circumstances. The Commission is not, however, amenable to approving a flotation cost adjustment based upon an average of flotation costs for other utilities, as Mr. Hevert calculated in his direct testimony. Despite all of the testimony and argument on this issue, the Commission finds no basis to consider flotation costs in establishing AIC's cost of common equity in this proceeding.

f. Approved ROE

The Commission notes that no party's position is without flaw as indicated by the parties' respective testimony in this proceeding. Each party has advocated a cost of equity that other parties believe reflects incorrect calculations through subjective, biased inputs. However, the Commission does not believe the imperfections in the models presented in this case are so flawed as to warrant an outright dismissal of the model for purposes of determining a reasonable rate of return. The Commission, based upon the cost of equity evidence presented, does not believe that any party's cost of equity position stands out as being sufficiently superior to any other position, such that a single party's estimation technique should prevail. Accordingly, the Commission will weight each position equally by taking an average of the positions advocated by AIC, Staff, AG/CUB, and IIEC's multi-stage DCF analyses, which, as previously stated, is the appropriate model upon which to rely in determining AIC's cost of equity. The Commission notes that AIC witness Hevert provided a range of DCF results from 9.51 to 11.54. The Commission will utilize the midpoint of that range (10.53%) for purposes of this proceeding. The Commission believes, based on the record before it, that blending the parties' proposals in this manner results in an average return that significantly diminishes any perceived upward or downward bias as set forth in the different positions of the parties.

The Commission further notes that a certain level of confusion arose with respect to the Proposed Order in the instant proceeding due to a scrivener's error in the gas revenue requirements. This apparently occurred as a result of the Proposed Order's use of numbers in an earlier version, instead of the Corrected version, of IIEC witness Gorman's Direct Testimony. The unintentional error was subsequently corrected. The Commission finds this scrivener's error in the Proposed Order to be a non-issue. As such, any suggestion that IIEC's multi-stage DCF not be included in the average of DCF results, is unwarranted.

Additionally, the Commission will accept the CAPM analysis of Staff and will average Staff's CAPM results with the averaged DCF results to derive a ROE. Finally, the Commission will make a downward adjustment to the cost of common equity to reflect the reduced risk resulting from the existence of the uncollectibles riders. The Commission concludes that AIC's gas operations should be authorized a ROE of 9.06%. The table below illustrates how the ROE was derived.

<u>DCF Results</u>

AIC	10.53%
Staff	8.63%
IIEC	8.43%
AG/CUB	8.90%
Average	9.12%
CAPM	9.31%
Estimated ROE	9.22%
Risk Adjustment	0.16%
Approved ROE	**9.06%**

H. Authorized Rate of Return on Rate Base

Having reached conclusions regarding all contested aspects of ROR, the Commission finds that AIC's gas operations should be authorized a return on rate base of 8.332%. The table below illustrates how the return~~s~~ on rate base was derived.

Authorized Rate~~s~~ of Return on Rate Base

AIC Gas Delivery Services

Capital Component	Balance ($)	Proportion	Cost (%)	Weighted Cost (%)
Short-term Debt	6,473,198	0.183%	2.24	0.004
Long-term Debt	1,591,564,788	44.878%	7.44	3.339
Preferred Stock	59,158,692	1.668%	4.98	0.083
Common Equity	1,889,251,000	53.272%	9.06	4.826
Bank Facility Fees				0.080
Total	3,546,447,678	100.000%		**8.332**

VII. COST OF SERVICE

As a part of every rate case, the Commission must determine what portion of a utility's costs each class of customers will be responsible for. AIC divides retail natural gas customers into six rate classes. The GDS-1 Residential Gas Delivery Service rate class tariff contains customer and delivery charges for residential customers. The GDS-2 Small Gas Delivery Service rate class tariff includes customer and delivery charges for non-residential customers whose highest Average Daily Usage ("ADU") is less than 200 therms per day. The GDS-3 Intermediate General Gas Delivery Service rate class tariff includes customer and delivery charges for non-residential customers whose highest ADU is equal to or greater than 200 therms per day and less than 1,000 therms per day. The GDS-4 Large General Gas Delivery Service rate class tariff includes customer, delivery, demand, and Maximum Daily Contract Quantity ("MDCQ") overrun charges for non-residential customers whose highest ADU is greater than 1,000 therms per day. The GDS-5 Seasonal Gas Delivery Service rate class tariff includes customer, delivery, and demand charges for eligible non-residential customers willing to limit gas usage on days when the average forecast temperature is 25°F or less. The GDS-7 Special Contract Gas Delivery Service tariff is available to any existing or prospective customer located within such distance of an interstate natural gas pipeline providing gas transportation service that bypass of AIC's gas distribution system is, in AIC's judgment, economically feasible and practical.

Generally, the Commission prefers to allocate costs among the various classes as close to the cost of serving each class as is reasonably possible and/or appropriate. The purpose of doing so is to assign costs to those who cause them. The Commission typically accomplishes this goal through a COSS. A COSS compares the cost each customer class or subclass imposes on the utility's system to revenues produced by each class or subclass. A properly performed COSS shows the cost to serve each class or subclass and the ROR for each class or subclass. Customer classes or subclasses with a ROR equal to the total system ROR are paying their cost of service. Customer classes paying less than the total system ROR are not paying their cost of service. From time to time circumstances arise that warrant allocating costs at least in part on non-cost based criteria. Whether such circumstances are present in this proceeding is discussed below.

A. Resolved Issue - Allocation of Rider TBS Costs to Gas Customer Classes

AIC proposes an unbundled, subscribable transportation banking service presented in Rider Transportation Banking Service ("Rider TBS"). AIC 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.

For Rider TBS to be approved, Staff believes that it should not only make sense from a policy perspective, but that AIC must demonstrate that the rates charged under the rider are reasonable, i.e., cost based. Staff witness Rukosuev recommends that Rider TBS be approved for the following reasons: (1) his primary concerns with the gas Rate Zone COSS have been addressed, (2) the allocation of costs to the customer classes are based upon various allocation methodologies Staff finds acceptable, and (3) AIC’s customers want alternative banking services. AIC agrees with Mr. Rukosuev's recommendation as it regards cost of service and considers this issue resolved with respect to the allocation of costs to the customer classes under Rider TBS. The Commission finds the resolution of this issue reasonable for purposes of this proceeding and adopts it.

B. Contested Issues

1. Use of AIC's Gas COSS

On August 26, 2010, AIC's three legacy utilities initiated Docket No. 10-0517 by filing a petition with the Commission seeking approval of certain modifications to the manner in which they recorded and maintained various accounting data upon executing the reorganization that created AIC on October 1, 2010. Among the five proposed modifications was a request that the newly formed utility be allowed to provide in future rate cases a single set of testimony and schedules under Part 285, 83 Ill. Adm. Code 286 "Submission of Rate Case Testimony" (“Part 286"), and Part 287; a single class COSS; a single jurisdictional COSS and revenue requirement; a single combined rate base; and a single combined capital structure for its electric and for its natural gas businesses. Before Docket No. 10-0517 was resolved, however, AIC filed on February

18, 2011 the Proposed Tariffs leading to the initiation of this rate proceeding. The Proposed Tariffs reflected the implementation of AIC's still pending accounting proposals in Docket No. 10-0517. On March 15, 2011, the Commission entered an Order in Docket No. 10-0517 accepting in part and rejecting in part the accounting proposals. Among the proposals rejected are the modifications described above concerning the next rate case filing (excluding those pertaining to capital structure). The Commission also observed in its conclusion that if AIC already implemented its proposals, it did so at its own risk and expense. Docket No. 10-0517 Order at 22.

AIC's decision to file the Proposed Tariffs based on its unapproved proposals in Docket No. 10-0517 have given rise to a significant contested issue. In response to the February 23, 2011 deficiency letters seeking separate information for natural gas service in each Rate Zone, AIC provided separate COSS on March 24, 2011. Whether these COSS are sufficiently reliable upon which to base rates is in much dispute.

a. AIC Position

In support of its Rate Zone COSS submitted in response to the February 23, 2011 deficiency letters, AIC asserts that Staff found acceptable AIC’s customer class allocators used therein. AIC also understands that Staff found the Rate Zone COSS consistent at the functional level and a sufficient basis for assessing Rate Zone costs overall. AIC recognizes that Staff expressed concern with the accuracy of the Rate Zone allocations of FERC account and subfunction balances for plant and reserve. But in response to that concern, AIC states that it adjusted the inputs for the allocated FERC account balances in its rebuttal testimony to improve the Rate Zone COSS from a cost causation standpoint.

Despite having made this effort to improve the COSS, AIC laments that Staff is still not satisfied. AIC disagrees with Staff's contention that its adjustments presented in its rebuttal testimony came too late to provide Staff with sufficient time to determine if the Rate Zone COSS provide a reasonable cost foundation. AIC points out that while Staff rejects any use of the rebuttal Rate Zone COSS for establishing revenue targets for AIC’s customer classes, no other party agrees with Staff’s position. AIC urges the Commission to dismiss Staff's concern.

To counter Staff's arguments, AIC asserts that its rate design and pricing methodology did not change from its original February 2011 filing, which it understands Staff approved of in its direct testimony. The only changes were to the Rate Zone inputs (also known as the amounts for the individual FERC accounts in the models themselves). As a result of those changes, AIC contends that the revised FERC account data more closely aligned with the legacy utilities’ historical costs, which was Staff’s principal concern. AIC insists that the incremental review following AIC's submission of its rebuttal testimony gave Staff sufficient time to examine the FERC input changes. AIC understands that Staff now agrees that the rebuttal Rate Zone COSS now use consistent data to derive Rate Zone balances at the functional and FERC account levels and address discrepancies at the subfunctional level within individual FERC accounts. If Staff had any other specific class cost or revenue allocation issues (beyond the FERC account Rate Zone adjustments), AIC contends that Staff could have identified them in its direct or rebuttal testimony. While Staff complains it had a truncated timeframe to review AIC's rebuttal Rate Zone COSS, AIC states that any particular cost or revenue allocations that require additional review by Staff remain unknown.

AIC acknowledges that it did not present changes to its ratemaking proposals in its deficiency response and then presented a revised set of cost studies and ratemaking proposals in rebuttal testimony. AIC reiterates that it took these steps to address Staff's concerns. According to AIC, changes to customer class revenue allocation methodologies are common during the course of rate cases. AIC argues that the fine tuning of the product to an improved and more accurate cost model should be encouraged, not disparaged.

b. Staff Position

Staff expresses frustration with AIC's preparation and presentation of its COSS in this proceeding. To begin with, rather than wait for the resolution of the docket that AIC itself initiated, Staff criticizes AIC for filing the Proposed Tariffs based on the presumption that it would receive the relief requested in Docket No. 10-0517. There is no question that the filing of a single natural gas COSS for the entire Illinois service territory constitutes a change from AIC’s previous rate cases (Docket Nos. 09-0306 et al. (Cons.)) where the legacy utilities separately filed for their respective electric and gas operations separate COSS. Staff avers that AIC's behavior reflects a knowing disregard of the regulatory process.

Staff cites the testimony of AIC witness Jones to buttress this conclusion. Mr. Jones acknowledges that AIC was well aware that, at the time of its initial filing, the Commission had yet to decide in Docket No. 10-0517 between using one or three COSS (for each type of service) for ratemaking. Tr. at 763. Mr. Jones states that he was not aware of any concern expressed within AIC before the initial filing that the filing might not be consistent with a Commission Order in Docket No. 10-0517. Id. at 756. Staff points out that AIC did not even consider providing three Rate Zone COSS for each service type in its initial filing to address the possibility that the Commission would rule against AIC on the COSS issue in Docket No. 10-0517. Staff also challenges Mr. Jones’ claim that “at no point did AIC attempt to take preemptive measures that limit the Commission’s range of action.” Ameren Ex. 13.0 at 15. When asked directly whether he considered filing a single COSS before the Commission decided between one and three COSS in Docket No. 10-0517 to be a preemptive measure, Mr. Jones insisted it was not. Tr.. at 762. Staff counters that the available evidence says otherwise and avers that filing a single COSS was a preemptive measure with adverse consequences for the parties and the regulatory process.

When AIC did submit three COSS for each service type on March 24, 2011 in response to the February 23, 2011 deficiency letters, Staff complains that they presented a number of problems. First, Staff states that it lost a month in its review of the filing. Second, the six Rate Zone COSS were significantly flawed in Staff's opinion. Third, the deficiency Rate Zone COSS were not accompanied by testimony or explanation of how they were prepared which, Staff contends, further inhibited the parties' review. Fourth, Staff states that the March 24, 2011 reply to the deficiency letters contained no rate design changes which means that AIC continued to base rates on a single gas COSS despite the Commission's directive in Docket No. 10-0517 that these be based on the three separate Rate Zones.

Staff relates that Staff witness Rukosuev extensively explored the shortcomings in the March 24, 2011 Rate Zone COSS, identifying various problems with the balances for both plant and reserve for depreciation accounts. Staff maintains that 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. One problem troubling Staff concerns the accuracy of the costs presented at the FERC account level which were determined in a different way than in previous COSS for the three legacy utilities. The March 24, 2011 Rate Zone COSS 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. Staff is concerned because AIC 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, Staff contends, evidence from AIC's previous rate cases, Docket Nos. 09-0306 et al. (Cons.), suggest 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. Staff therefore concludes that there is no reason for AIC to assume that the ratios of FERC account balances between the three Rate Zones will be the same.

Aside from the concerns presented above, which focus on how functional categories are broken down into individual FERC accounts, Staff also expresses 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 gas COSS presented in the original filing. Staff presented an illustration of the differences in individual FERC accounts between Rate Zone and Illinois-Wide COSS reserve for depreciation. (See Staff Ex. 15.0, Schedule 15.04)

Another concern of Staff's is that these problems with AIC's March 24, 2011 Rate Zone COSS also affect those expenses that are allocated according to plant totals. Staff contends that any inaccuracies in distribution plant balances at either the FERC account or subfunction level distorts the resulting allocations of these expense accounts.

Taken together, Staff avers that these shortcomings affect the degree to which the March 24, 2011 Rate Zone COSS can be used in the ratemaking process. The problems at the FERC account level, Staff explains, mean they cannot be used to allocate revenues or design rates at the customer class level. Staff, however, recognizes that the COSS can still play a limited role in guiding the allocation of total system costs to the three Rate Zones. Staff reminds the Commission that the problems with the studies lie not at the general functional level but rather with the individual FERC accounts. Staff states that 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. Staff suggests that the higher return for Rate Zone 3 indicates it should receive a smaller increase than Zones 1 and 2. Since Rate Zone 3 has higher current rates, Staff states that the results provide support for moving closer to uniform rate levels as AIC proposes.

Staff acknowledges that AIC revised the Rate Zone COSS in response to Staff's concerns. While Staff considers the Rate Zone COSS provided in AIC's rebuttal testimony to be an improvement upon AIC's previous efforts in this case, Staff nevertheless finds the COSS problematic. Staff is frustrated by the length of time AIC took to address the shortcomings in its previous COSS approaches which severely impaired the review by Staff and other parties. Staff reiterates that AIC failed to submit the required six COSS with its February 18, 2011 Proposed Tariffs. On March 24, 2011, Staff continues, nine days after the March 15, 2011 Order requiring separate Rate Zone COSS, did AIC submit the required Rate Zone COSS in response to the February 23, 2011 deficiency letters. Staff observes that the March 24, 2011 filing lacked an explanation of how those COSS were developed. Not until five months after the filing of the Proposed Tariffs, Staff points out, did AIC witness Jones present a revised set of cost and ratemaking proposals based upon the revised COSS for each of the three Rate Zones and service type. Staff complains that this sequence of events left it and other parties with only rebuttal testimony, hearings, and briefs in which to discuss and debate AIC's revised ratemaking proposals. Staff concludes that this truncated schedule inhibited a complete and thorough discussion of the rate design issues in this case.

Based on the forgoing, Staff submits that the revised Rate Zone COSS presented in AIC's rebuttal testimony could not be verified as reasonable for ratemaking purposes in this proceeding. Staff explains that the significant delay in producing the revised Rate Zone COSS made it difficult to determine whether these studies do, in fact, provide a reasonable foundation for ratemaking. Each COSS, Staff continues, contains hundreds of cost accounts that are allocated by a variety of allocators based on data developed for each Rate Zone. According to Staff, a thorough review of the accuracy of each study requires considerably more time than that provided in the rebuttal stage of a rate case.

c. Kroger Position

Kroger recommends that the Commission rely upon the COSS that AIC offered in its rebuttal testimony for purposes of revenue allocation among both Rate Zones and customer classes in this proceeding. Kroger contends that AIC provided in its rebuttal testimony reasonable certainty about the costs of serving the various groups of AIC's customers. Kroger states further that the Commission should use AIC's rebuttal COSS in order to uphold the principle of cost causation in setting rates.

d. IIEC Position

IIEC supports the use of AIC's Rate Zone COSS as presented in AIC's rebuttal testimony as a starting point for revenue allocation in this proceeding, subject to the modifications proposed by IIEC and discussed elsewhere in this Order.

e. Commission Conclusion

With regard to the gas COSS, the Commission understands that Staff and the other parties are in general agreement that AIC's gas COSS presented in its rebuttal testimony are sufficient for purposes of this proceeding.

As discussed above, in Docket No. 10-0517, the legacy utilities sought permission to do what AIC eventually did when it filed tariffs leading to the initiation of this rate case: AIC filed a single gas COSS and a single electric COSS for all of the Rate Zones combined. AIC did so even before receiving permission to do so in Docket No. 10-0517. To remedy this problem, the Administrative Law Judges issued on February 23, 2011 a deficiency letter to AIC directing it to submit the required gas COSS for each Rate Zone. The Commission entered an Order in Docket No. 10-0517 on March 15, 2011 consistent with the deficiency letter. AIC complied with the deficiency letter on March 24, 2011. The Commission understands that AIC had ceased tracking individual costs by Rate Zone prior to the resolution of Docket No. 10-0517 and therefore provided separate COSS by Rate Zone based on various allocators. Using such allocators is consistent with what the legacy utilities had proposed in Docket No. 10-0517. While it is clear that the gas COSS offered in AIC's rebuttal testimony are an improvement over the COSS submitted with the initial tariff filing, the Commission cannot conclude that they are without flaws. While AIC's gas COSS offered in its rebuttal testimony is not perfect, it is the least objectionable alternative for establishing the cost of serving each rate class. Accordingly, the Commission adopts AIC's gas COSS as presented in its rebuttal testimony for purposes of setting rates in this proceeding.

But the Commission's frustration with this issue does not end here. When the legacy utilities initiated Docket No. 10-0517, it is not plausible that they truly felt they had no obligation to obtain the Commission's permission to submit a single gas COSS, as AIC suggests. Otherwise there would not have been any reason to include such a request in its petition. But rather than responsibly wait a few weeks for the conclusion of Docket No. 10-0517, AIC apparently ceased recording costs by Rate Zone and chose to file its new tariffs assuming it would receive the relief it requested. To be clear, a utility may file a rate case at the time of its choosing. But at the same time, AIC's choice of action leads one to question AIC's judgment and perhaps its motives. By taking the action it did, AIC effectively obtained in this regard what the Commission found it should not have.

VIII. REVENUE ALLOCATION

While determining the cost of service is concerned with identifying the cost to the utility of serving each rate class, determining the appropriate revenue allocation (along with rate design) is concerned with establishing how much of a utility's revenue requirement will be recovered from each rate class. The revenue recovered from a particular rate class may be different from the cost of serving that particular rate class for various reasons.

With respect to the allocation of the gas revenue requirement to Rate Zones and customer classes, in its rebuttal testimony Staff recommended that the Commission accept its proposal to move half the distance from equal percentage, across-the-board increases to full cost-based revenue allocations for AIC's Rate Zones, but also accept AIC's proposed modification to move individual rate classes toward cost based rates subject to a constraint that no class exceeds an increase of 1.5 times the overall average increase allocated to the respective Rate Zone. Thus, the first step in the revenue allocation method calculates the overall average percentage increase to AIC (total percentage increase for all Rate Zones). The second step examines the individual cost-based revenues for the three Rate Zones. The revenue allocation moves proposed gas revenues for the three Rate Zones half the distance from an across-the-board (step 1) to a fully cost-based approach (step 2). In response, AIC suggested modifying Staff's proposed gas revenue allocation methodology to extend to individual rate classes, subject to a constraint that no class exceed an increase of 1.5 times the overall average increase allocated to the respective Rate Zone. Staff agrees with this modification and no other party has raised concerns about this issue. The Commission finds the agreed gas revenue allocation reasonable for purposes of this proceeding and adopts it.

IX. RATE DESIGN

A. Resolved Issues

1. Billing Units

AIC and Staff agree that AIC's gas forecasts for customers and usage appear to be reasonable. The Commission finds that AIC's gas forecasts for customers and usage are appropriate, and will be adopted for use in this proceeding.

2. Increase for Charges (except GDS-1 and GDS-5)

The parties indicate that AIC's only proposed change to the Rate GDS-1 tariff reflects its proposed revenue requirement. For Rate GDS-1, the parties state that the determined constrained revenues by Rate Zone were split into Customer Charge and

Delivery Charge revenues, and the individual Rate Zone's Customer Charge revenues were then divided by the respective number of customer bills in each Rate Zone to derive the proposed monthly Customer Charge. They further note that the residual Delivery Charge revenue for each Rate Zone was then divided by the annual therms to derive the therm/unit Delivery Charge.

AIC states it proposes no tariff charge changes to the Rate GDS-3 tariff other than to adjust rates to reflect its proposed revenue requirement. AIC notes that 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 Ex. 13.6G. Also, AIC proposes no tariff charge changes to the Rate GDS-5 tariff other than to adjust rates to reflect its proposed revenue requirement. In keeping with the Rate Moderation proposal, Staff supports adoption of AIC's Rates GDS-1, GDS-3, and GDS-5 rate design proposal. The Commission finds this proposal to be reasonable, and it will be adopted for this proceeding.

3. Single PGA/Rider PGA

AIC proposes in this proceeding to adopt a single PGA tariff covering all three of its Rate Zones, where currently there is a separate PGA tariff for each of the three Rate Zones, corresponding to the three legacy utilities – Rate Zone 1 (AmerenCIPS), Rate Zone 2 (AmerenCILCO), and Rate Zone 3 (AmerenIP). Staff reviewed AIC's request and the benefits AIC asserted would result from the use of a single PGA, and found no reason to dispute AIC's request.

Based on analyses prepared by AIC and Staff, Staff agrees with AIC that the monetary effect on customers of a single PGA tariff would be minimal. Staff 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 1. Currently, there is no demand component in the rates charged to those customers as there is in Rate Zones 2 and 3. However, under a single PGA, all GDS-4 Rider S customers would be subject to a DGC.

The parties indicate that the analyses show that all customers but one would have paid less over a 12-month period beginning November 2009 and ending October 2010. 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 12-month period AIC will set rates by legacy Rate Zone to credit/charge the over/under recovered balances to the applicable customers, and 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.

Staff recommends that within the 12-month time frame proposed by AIC, the process continue until the respective rate per therm is less than .01 cents per therm. Staff recommends that the balance remaining when a rate can no longer be set, or at the end of the 12-month period, 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. On alternate months the rates should be set at $0.00. Staff suggests this allows time for AIC to better gauge the respective over/under recovered balance before the next billing month. AIC agrees with Staff's recommendations.

If a single PGA is approved by the Commission, Staff recommends that the following language be inserted in Rider PGA to describe (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.

AIC agrees with the recommended language changes.

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:

> 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.

The Commission finds that the parties are in agreement that it appears appropriate at this time to allow AIC to have a single Rider PGA which would cover each of its three Rate Zones. Staff has identified some additional language which should be added to AIC's Rider PGA, and AIC has indicated that it has no objection to Staff's recommendations. It also appears to the Commission that no party to this proceeding has indicated it has any objection to a single Rider PGA which would cover AIC's Rate Zones. The Commission believes that that it is appropriate to authorize AIC to institute a single PGA to cover all of the Rate Zones, subject to the conditions identified by Staff.

4. Conformity of GDS-2 Customer Charge - 600 Therms

AIC proposes to conform the GDS-2 rate structure of Rate Zone 3 to the rate structure of Rate Zones 1 and 2. Currently, Rate Zones 1 and 2 have two Customer Charges – one for Customers that use less than or equal to 600 therms per year and a second for Customers who use more than 600 therms per year. Conversely, Rate Zone 3 has one Customer Charge, regardless of annual use. AIC proposes that Rate GDS-2 in Rate Zone 3 would also have two Customer Charges based on annual use.

Staff recommends that the Commission approve the changes to GDS-2 to conform the GDS-2 Customer Charge rate structure for Rate Zone 3 to that of Rate Zones 1 and 2, as AIC's rate design proposal, which is to conform the GDS-2 Customer Charge rate structure for Rate Zone 3 to that of Rate Zones 1 and 2, is in the best interest of its customers.

The Commission finds this recommendation to be reasonable, and it will be adopted for this proceeding.

5. Conformity of GDS-4 Demand Charge - MDCQ

AIC indicates that it proposes a number of changes to the GDS-4 rate class to make the Rate Zones more uniform. AIC proposes that Customer Charges for all Rate Zones be based on MDCQ. According to AIC, use of MDCQ provides a closer approximation of the design load that gas planning engineers estimate is required to serve a customer, which in turn provides a closer link to cost of service. AIC states that for Rate Zone 1, delivery charges for both Rider S and Rider T customers will no longer be distinguished by pressure, and demand charges for Rate Zone 1 would be added and will be distinguished by operating pressure for both Rider S and Rider T customers. AIC asserts that this approach to rate design for the GDS-4 customer class was developed as a step toward rate structure uniformity.

Staff recommends that the Commission accept AIC's proposal to move Rate Zones 1, 2, and 3 GDS-4 toward price uniformity. Staff avers that AIC's rate design proposal for the GDS-4 customer class is in the best interest of its customers. Despite the problems with AIC's revised Rate Zone COSS 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 AIC's subsequent evaluation and findings with respect to the GDS-4 customer class, provide a sufficient basis for adoption of this proposal.

The Commission finds this proposal to be reasonable, and it will be adopted for this proceeding.

B. Contested Issues

1. GDS-1 Customer Charge

a. AIC Position

AIC notes that in its 2007 rate case, Docket Nos. 07-0585 et al. (Cons.), the Commission directed AIC to modify its monthly customer charges for the GDS-1 and GDS-2 classes so that 80% of delivery services costs were recovered through the customer charge. Order (September 24, 2008) at 237. AIC notes the Commission further ordered "that the approved ratio of fixed costs recovered from the customer charge and volumetric rate must remain in place until at least December 2012." Id. at 238. AIC states that the Commission affirmed that rate design in AIC's 2009 rate case. AIC notes that the Commission also recently approved recovery by Nicor of 80% of its costs through the customer charge. Docket No. 08-0363 Order (March 25, 2009) at 90-91. AIC asserts that the Commission has also consistently supported, as a policy matter, the recovery of a greater portion of fixed costs through the customer charge. See Illinois-American Water Co., Docket No. 07-0507 Order (July 30, 2008) at 122; Illinois-American Water Co., Docket No. 09-0319 Order (April 13, 2010) at 169; ComEd, Docket No. 10-0467 Order (May 24, 2011) at 232. Consistent with that directive and Commission policy, AIC notes that it has been recovering 80% of its residential class revenue requirement through the customer charge since 2008. AIC proposes in this docket to continue recovering 80% of the class revenue requirement for the GDS-1 and GDS-2 customer classes through the customer charge, and notes that Staff accepts this proposal.

AIC witness Althoff explains the reasoning behind this proposed continued recovery, testifying that the vast majority of AIC's gas costs of service, over 97% in fact, are "fixed" in nature in that they do not vary with usage. AIC states this is best understood by breaking those costs down into two categories, "capacity" related costs and "customer" related costs. AIC asserts that "capacity" related costs of service are those costs tied to the tangible assets necessary to provide gas utility service to customers, such as gas distribution mains and gas storage facilities, noting that the costs of these assets, once installed, do not vary with monthly customer usage and so are fixed. AIC states that "customer" related costs are similarly "fixed" costs. AIC indicates that "customer" related costs are based on the number of customers served by AIC and include the costs of meter installations, services, customer administration and billing, and meter reading, among others, which costs do not vary with usage. AIC asserts that it is appropriate to recover costs such as these which do not vary with usage, and thus are "fixed," through a corresponding pricing mechanism, a fixed customer charge.

While GCI characterize 45% of AIC's costs as "demand" costs, AIC claims these costs are more properly categorized as "fixed" costs because they are capacity-related, meaning they must be incurred to make the gas system available to customers: even if a customer uses no gas. Ms. Althoff explains that customers expect that the system will be available to deliver gas when they demand it, and that availability has a cost, irrespective of usage. For this reason, AIC argues that GCI's characterization of these costs as "demand" costs is incorrect.

AIC notes that GCI witness Rubin contends that AIC's costs of service should be evaluated over the long run, and, when so evaluated, they are in fact not "fixed" costs. As AIC witness Althoff explains however, costs traditionally considered by economists as "variable," such as labor and customer service costs, in fact do not change in the utility setting with short-term fluctuations in load. AIC indicates that the Commission also recently rejected the same argument presented by GCI in ComEd's most recent rate case, Docket No. 10-0467.

AIC states that GCI also argues that AIC's proposed residential customer charge adversely impacts low use customers and raises rate discrimination and social welfare concerns. AIC notes that GCI contends that AIC's proposal shifts costs from high-use customers to low-use customers, but does nothing to improve the overall efficiency of service. GCI contends this could lead to inefficient consumption decisions, as consumers would not receive proper price signals reflecting the true cost of meeting customers' demands for energy services.

AIC contends however, that because AIC's costs to distribute gas services are primarily fixed, the cost to provide such service to low-use customers differs little from the cost to provide such service to high-use customers. AIC states its proposal sets the proper pricing signal for customers with respect to those costs by establishing fixed charges for such fixed costs, while noting that these fixed distribution charges comprise only a small portion of a residential customer's bill. AIC asserts that a significant portion of the bill is comprised of the customer's gas commodity charge which is tied to therm usage, and it is this therm charge which sends the appropriate pricing signal regarding the customer's gas consumption.

AIC opines that recovery of costs through a higher volumetric charge, as apparently championed by GCI, could result in a subsidy of low-volume customers by high-volume customers, which would penalize those customers because, under GCI's proposal, they would pay more than their appropriate share of the fixed costs to serve them. AIC notes that in alleging an inappropriate "cost shift," GCI ignores that AIC has been recovering 80% of its residential class revenue requirement through the customer charge since the Commission's directive that it do so in AIC's 2007 rate case.

AIC notes that GCI also argues that certain of the "capacity" related costs AIC considers "fixed" in nature are, in fact, not "fixed" at all. Mr. Rubin points specifically to the cost of gas storage fields, which he contends are "variable." AIC explains however, that the cost of service for underground storage fields is tied to tangible assets including land and land rights, structures and improvements, wells, non-recoverable natural gas necessary for the fields to operate, lines, and storage equipment, and to the expense incurred to operate and maintain those facilities. Therefore, AIC asserts that storage costs are fixed.

AIC claims that over 97% of its costs of gas service are "fixed" costs, as they do not vary based on gas consumption, and to recover such costs through variable charges sends consumers the wrong pricing signal. AIC opines that when proper pricing signals are utilized, ratepayers' consumption decisions will be based on the actual cost of delivery service. AIC suggests that its proposal to continue recovering 80% of the class revenue requirement for the GDS-1 and GDS-2 customer classes through the customer charge, as approved by the Commission in the AIC's last two rate cases, should be approved.

b. GCI Position

GCI states that AIC is proposing to recover its proposed increase in revenue requirement from residential customers by continuing to recover approximately 80% of its residential cost of service through its customer charge. GCI notes that AIC's existing residential rates consist of a monthly customer charge and a per-therm distribution charge for each of the three Rate Zones AIC established for this proceeding. Under AIC's proposal, Rate Zone 1 would go from a customer charge of $19.31 to $22.39 and the per-therm distribution charge would go from $0.07724 to $0.08971. GCI states that the Rate Zone 2 customer charge would increase to $18.41 from $15.60, while the per-therm charge would go from $0.05649 to $0.07035. Lastly, GCI indicates that Rate Zone 3 has a customer charge of $19.57 which would increase to $22.01, and has a per-therm charge of $0.07589, which would increase to $0.08982.

GCI notes that over the past few AIC rate cases, AIC has had a steady, non-cost-justified increase in the customer charge portion of the monthly bill based on AIC's definition of "fixed" costs and the supposition that its delivery service costs are not affected by gas consumption. GCI argues however that AIC's own COSS shows that there are substantial demand-related costs that are incurred because of the amount of gas consumed by customers.

In this case, GCI states that AIC is proposing per-therm distribution rates that are significantly less than the per-therm demand costs incurred to serve residential customers, noting that the demand cost is approximately 19 cents per therm, while AIC is proposing distribution charges of between 7 and 9 cents per therm. In effect, GCI asserts AIC proposes to recover most of its demand-related costs on a per-customer basis, which is inconsistent with the setting of cost-based rates for utility service. GCI opines that AIC has tremendous diversity within its residential classes, ranging from customers who do not use natural gas for space heating to those who use many hundreds of therms per month during the winter for space heating. GCI asserts that this diversity means that these customers in fact place different demands and impose different costs on AIC's natural gas distribution system.

GCI states that while demand-related costs account for approximately 45% of AIC's total cost of serving residential customers ($107 million out of $235 million), AIC has proposed rates that do not recover these residential demand costs from the customers who cause them to be incurred (those customers who use more gas). Instead, GCI avers that AIC has proposed rates that would require low-use residential customers to provide substantial subsidies to high-use residential customers – charging higher-use customers less than one-half the demand cost that they impose on the system.

GCI states that utility rates rest on a fundamental notion that rates should be "just and reasonable" and that rates should not improperly discriminate among customers; that people should not be asked to pay different rates for the same service. In order to determine whether rates are just, reasonable, and not improperly discriminatory, GCI indicates the Commission must rely on information about the cost to serve different types of customers. GCI asserts that differences in rates among different types of customers should be related to differences in the cost of providing service so that regulators can have confidence that the rates are not improperly discriminatory.

While AIC has identified these types of costs, GCI complains that AIC does not propose rates that fairly recover that cost from the customers who cause it. GCI avers that AIC's proposed rates are highly discriminatory against low-use residential customers because they would require those customers to pay substantially more than the cost that is incurred to serve them. GCI opines that the evidence shows that heating customers place dramatically larger demands on the system than do non-heating customers, and larger heating customers place greater demands on the system than smaller heating customers, therefore, it is grossly unreasonable to recover most demand-related costs on a per-customer basis.

GCI, therefore, recommends a transition to cost-based residential rates by recommending any rate increase allocable to residential customers be recovered solely from the per-therm distribution charge. GCI notes that AG/CUB Ex. 2.4 shows the residential rates that it recommends under AIC's proposed revenue requirement, and notes there would not be any increase in the GDS-1 customer charges in this case.

GCI recommends the Commission seriously consider the fairness and reasonableness of how a disproportionate increase in the minimum charge in this case would impact low usage customers. GCI argues the resulting rate design would send a confusing message to low usage consumers who could experience a significant increase in the overall rate that they pay, even if they are conserving in an aggressive way. By dramatically increasing monthly customer charges, GCI claims customers could see any small savings in volumetric charges that will result from conservation offset by a huge increase in the minimum portion of their bills.

While AIC apparently refers to "fixed" costs to mean costs that do not vary in the short-term as the throughput of gas changes, GCI submits that a standard economic definition of a "fixed" cost is one "whose quantity cannot be changed during the period under consideration," and the relevant period, short or long, for determining whether a utility cost is fixed or variable should be the long run.

GCI states that AIC's COSS shows its total proposed revenue requirement is $343,728,700, which AIC then divides by the average number of customers over a year to determine that its fixed cost per customer of $34.89 on a total-company basis ($26.07 for residential customers). On the following line in its study, GCI notes it then calculates what it calls "Total fixed 80% recovery," that is, the recovery of 80% of so-called "fixed" costs through the customer charge, which is $27.91 on a total-company basis and $20.85 for residential (GDS-1) customers. GCI asserts this shows that AIC has treated all of its costs as being fixed, yet for the DS-1 class AIC's own data show that it incurs substantial costs related to the peak demand that each residential customer places on the system. GCI claims these demand-related costs are apparent in the sizing of distribution mains, storage facilities, and other types of distribution facilities and related O&M costs. GCI indicates that AIC's COSS shows residential demand-related costs to be $107,174,100, which, if recovered from residential customers in proportion to their annual consumption (that is, recovering the cost on a per-therm basis), the demand cost per therm would be 18.99¢ per therm. GCI asserts these costs should be recovered from customers in proportion to the amount of natural gas that they use, particularly when that gas is used during the winter.

GCI claims that AIC's focus on the short run to determine whether costs are fixed or variable is not appropriate for setting utility rates or evaluating a utility's cost of service, and believes there is no support among reputable public utility economists or among public utility commissions for setting utility rates based on short-run marginal costs. GCI opines that such a method of utility pricing is simply a method of transferring wealth from one group of customers to another, and not only is there no discernible increase in overall societal welfare and no improvement in the efficiency of use of the utility's service, such a pricing proposal could lead consumers and utilities to make decisions that are not in their long-run best interests.

GCI avers that the essential flaw in pricing utility distribution service based on short-run marginal cost is that the industry exhibits economies of scale, which in turn means that the marginal cost declines as more of the product is supplied. In an industry that exhibits economies of scale, GCI states setting prices equal to short-run marginal cost results in the firm being unable to recover its costs. GCI asserts it is unreasonable and improper to treat most of AIC's costs as "fixed" and to recover them on a per-customer basis when AIC's own COSS shows that more than 45% of its cost of serving residential customers is related to those customers' demand for natural gas, therefore the Commission should adopt GCI's proposed residential rate designs for natural gas distribution service.

c. Commission Conclusion

In accordance with the Commission's directive in its 2007 rate case, the Commission notes that AIC has been recovering 80% of the class revenue requirement for the GDS-1 and GDS-2 customer classes through the customer charge. The Commission notes also that AIC has proposed to continue setting its customer charges using the same approach, and that Staff has accepted AIC's proposal on this issue. GCI, however, suggests that AIC has overstated its fixed costs, and suggests that AIC's COSS supports their argument.

The Commission finds that AIC's proposal to recover 80% of the fixed cost of serving GDS-1 and GDS-2 customers is in conformity with established Commission policy. The Commission also finds that AIC has properly accounted for its fixed versus variable costs in serving GDS-1 and GDS-2 customers, and has properly taken them into account in calculating its proposed customer charge. The Commission believes that GCI's opposition is contrary to the Commission's established policy to allow recovery of a greater portion of fixed costs through the costumer charge. The Commission, therefore, finds that AIC's proposed method for determining the customer charge is just and reasonable in this case.

2. GDS-5 - Expansion of Rate Class Availability

a. AIC Position

AIC notes that its current GDS-5 rate is a seasonal service that allows customers to avoid demand charges, provided they consume gas only on days when the average temperature exceeds 25 degrees Fahrenheit. AIC proposes retaining the GDS-5 temperature based customer class structure in its current form, and proposes no changes to the GDS-5 tariff.

AIC states that the GDS-5 tariff is the tariff most applicable to the GFA and its members. AIC states that GFA supports utilization of the current temperature based GDS-5 rate, however, GFA also proposes incorporating into the GDS-5 rate design additional tiers of customer charges applicable to small and intermediate customers of the GDS-2 and GDS-3 size, and revising the GDS-5 tariff accordingly. AIC notes that GFA witness Adkisson testifies that while all customers are eligible to receive the GDS-5 rate if they are willing to curtail their gas usage on certain days, as a practical matter, that rate is only available to large consumers because the GDS-5 customer charges are comparable to those for GDS-4 Large General Service Customers. AIC notes GFA claims the GDS-5 rate design does not send the appropriate pricing signals to small and intermediate GDS-2 and GDS-3 customers, contending that a typical small to intermediate size grain dryer would not be expected to utilize the GDS-5 rate because of the proposed high monthly fixed charges.

While GFA takes the position that a broader range of customer charges within the GDS-5 rate equal to that proposed for the GDS-3 rate would encourage greater off peak usage by those customers, AIC recommends that GFA’s proposal be rejected. AIC asserts GFA's position overlooks the fact that AIC must properly assess charges to recover the costs necessarily incurred to provide service to its customers. In this regard, AIC claims GFA’s proposal ignores the basis for the respective customer charges incorporated into the GDS-3 and GDS-5 rate designs. AIC asserts that GDS-5 rate customers who consume gas on days when the temperature is at or below 25 degrees Fahrenheit incur a demand charge based on that day’s use, thus, the GDS-5 rate structure requires interval metering based on discrete incremental measurements of gas consumption. In contrast, AIC states the GDS-3 rate structure does not assess demand charges, and as such, GDS-3 metering equipment is more simplistic and less costly. AIC believes the evidence shows that the average installed cost of a GDS-3 meter is approximately $5,400, while the average installed cost of a GDS-5 meter is $10,800. AIC notes these figures do not include the cost of regulators or interval metering equipment necessary for GDS-5. AIC avers further that because the design of the GDS-5 rate tariff offers a price break for seasonal usage to GDS-5 customers; meter reading and billing, too, are more complex and, as a result, more costly for GDS-5 grain drying customers relative to GDS-2 and GDS-3 general use customers.

AIC claims that if GDS-3 customers were to switch to the GDS-5 rate, AIC would be required to install this more costly demand metering equipment for those customers, and incur related costs, but those customers would not be assessed the appropriate customer charge under GFA’s proposal. AIC states the result would be cross-class subsidization; GDS-2 or GDS-3 customers using the seasonal rate would not pay enough to cover the associated costs, which would then have to be borne by other customers.

While GFA contends the installed cost of meters and regulators capable of recording discrete hourly and daily demands as required by the GDS-5 rate schedule are available and can be installed for less than $5,000, AIC contends that GFA’s analysis is inaccurate. AIC states that GFA’s estimation of the equipment necessary to serve GDS-2 and GDS-3 customers under the GDS-5 rate structure focuses on therm usage, ignoring other service criteria, and is therefore incomplete. Moreover, AIC asserts the equipment suggested by GFA and identified on GFA Exhibits 2.01G and 2.02G would not be appropriate for GDS-5 customers. AIC notes the regulator cost estimated by GFA is too low for the volumes of gas used by most grain dryers; the labor cost estimated by GFA to install GFA's proposed equipment is too low given that GDS-5 meter sets are greater in size, complexity, and installation time, than GDS-3 meter sets, and the total cost estimated by GFA to install a GDS-5 capable meter set for a GDS-2 or GDS-3 customer is inaccurate and low.

While GFA asserts that AMC's meter charges support its position, AIC claims the AMC tariff is not comparable. AIC alleges the AMC's cost development reflects the cost of service, net of accumulated depreciation, of the average cost of the equipment in AMC's plant records, in contrast to the costs of GFA Exs. 2.01G and 2.02G, which are current costs. AIC indicates it utilizes the current costs of the installed meters set by GDS customer groups to allocate the recorded plant costs of these assets. In other words, AIC states the $5,400 or $10,800 installed meter costs for GDS-3 and GDS-5 customers are used to allocate the historical plant dollars of the meter assets, and they cannot be compared to the AMC charges.

AIC argues that GFA's proposal also should be rejected in light of the admission that AIC would experience revenue erosion if a significant number of GDS-2 and GDS-3 customers switched to the GDS-5 seasonal rate, as GFA recommends. AIC notes GFA is not proposing the incorporation of an additional customer charge for GDS-2-size customers at this time, but rather claims there are 12 grain dryers' accounts which would be eligible to switch from the GDS-3 to the GDS-5 seasonal rate under its proposal. AIC asserts that if all 12 were to switch, the revenue erosion would be approximately $20,000 annually, based on AIC's requested rate increase, which revenue erosion AIC recommends the Commission find unacceptable.

AIC notes GFA also overlooks the additional, significant potential revenue erosion that would result if eligible GDS-3 customers other than those identified by GFA were to switch to the GDS-5 rate. AIC states it has over 80 other grain drying customers served under the GDS-3 rate structure, and if all were to switch rate classes, the revenue erosion and cost subsidization resulting from the difference in cost between GDS-3 and GDS-5 metering equipment would be significant. AIC notes that Staff indicates that GFA's proposal would add ambiguity for rate administration, which would result in uncertainty for recovery of a utility's approved revenue requirement. AIC asserts that GFA concedes it has not fully considered the ramifications of its proposal, therefore GFA's proposal should be rejected and AIC's GDS-5 rate design and tariff should remain unchanged.

b. GFA Position

GFA indicates that it supports expansion of the current temperature based GDS-5 rate to GDS-3 size customers, and claims that doing so would achieve greater utilization of, and revenues from, the AIC natural gas distribution system during the winter months while protecting system integrity. GFA notes the GDS-5 rate was specifically designed to provide benefits to all AIC customers by relieving the AIC distribution system peak, and is accomplished by encouraging GDS-5 customers to self interrupt when the temperature is 25 degrees or below. GFA claims that continuing to make the GDS-5 interruptible feature available only to GDS-4 customers and not GDS-3 customers would be a lost opportunity to provide further system wide benefit.

GFA states that while all customers are technically eligible for the GDS-5 rate, as a practical matter, the GDS-5 rate is only available to larger customers because the GDS-5 customer charges are in the same range as the GDS-4 Large General Service rate. GFA believes that AIC should add an additional tier to its range of customer charges within the GDS-5 rate for customers of the GDS-3 intermediate size. GFA claims adding this tier will encourage greater off-peak utilization of the AIC distribution system. GFA proposes an additional tier for customers having a MDCQ of greater than 200 and less than 1,000, which is the eligibility requirement for a GDS-3 customer, and proposes replicating the GDS-3's Customer Charges for this tier.

GFA notes that AIC opposes the additional tier, alleging that the DS-3 customer charge will not fully recover the cost of an interval demand meter, service line and other costs. GFA further notes that AIC claims that the cost of an interval demand meter and equipment of a GDS-3 size is about double the cost of a regular GDS-3 meter. GFA argues that its evidence shows that the cost of a complete installation of a regulator meter with demand recording capability with temperature and pressure compensation and data storage electronics is less than $5,000, or about the same as currently for a GDS-3 meter. GFA asserts that the GDS-3 customer charge is a reasonable proxy for GDS-3 size customer charge for an expanded tier in the GDS-5 rate.

Although AIC witness Althoff recites a higher meter cost for GDS-5 customers, GFA claims that she admits that the cost is for existing GDS-5 customers, most of whom are GDS-4 size customers. Because GDS-4 customers use a higher volume, GFA claims that they need larger, more expensive equipment than GDS-3 size customers. While Ms. Althoff points out that her analysis includes more than the cost of a meter and includes the cost of a regulator, and other related equipment, GFA argues that she does not take into account that a GDS-3 customer would not change its burners when switching to the GDS-5 rate and therefore the service line, meter and regulator and associated equipment would have the same flow capacity requirement as before. Although AIC complains that GFA's analysis does not take into account regulators or interval metering equipment, GFA notes that its Ex. 2.01G includes the cost of a regulator and interval metering equipment.

To further support its cost analysis, GFA notes that it checked AIC's meter charges in a neighboring state, Missouri, including AMC standard transportation tariff sheets 10 and 20.1, which are for a customer whose annual transportation requirements are expected to be 600,000 Ccf or less (therms or less), which GFA states approximates an AIC GDS-3 size customer. GFA states that the AMC standard transportation tariff contains a customer charge, an electronic gas administration charge and a meter equipment charge, which total $93.17 per month. Additionally, GFA notes the monthly meter equipment charge for electronically recording and telemetry of customer demands is $21.00. GFA opines that a conservative 1% per month of installed utility facility carrying charge equates to an AMC standard transportation meter cost of about $2,186, which is very close to the vendor meter quotes obtained by GFA. GFA avers that a monthly facilities carrying charge of 1.25%, equates to an even lower meter cost of $1,680, which may be possible when utilities purchase meters in larger quantities.

GFA indicates that AIC alleges that a massive switch to GDS-5 by GDS-3 customers is possible and that such an event would cause such enormous rate administration ambiguity and financial uncertainty for AIC, that GFA's proposal should be rejected, which concern is shared by Staff. While GFA believes that these concerns are overstated, to allay these fears and to mitigate any financial impacts on AIC, GFA proposes to delay implementation of the expanded GDS-3 customer charge tier to May 1, 2012. GFA states this delay will allow time for GDS-3 customers to assess the optional GDS-5 seasonal rate, time for AIC to implement the expanded GDS-5 rate after the Commission's final order, and to allow AIC to minimize any revenue erosion and adjust charges to actual when AIC files its next gas rate case. Additionally, GFA does not oppose implementing the expanded GDS-5 rate on an experimental basis.

While Staff raises the concern that GFA's proposal has the potential to set back the attainment of cost-based rates, GFA asserts that the GDS-5 rate was specifically designed to provide benefits to all AIC customers by relieving the distribution system peak by GDS-5 customers' self interruption when the temperature is 25 degrees or below. Moreover, GFA notes it has not proposed to change cost allocation to classes in this case and therefore its proposal cannot possibly set back the attainment of cost-based rates. GFA indicates that its proposal is to add another customer charge tier to the cost-based rate that is ordered in this case for GDS-5, and to use exactly the cost-based customer charge that the Commission orders in this case for the GDS-3 rate for GDS-3 size customers taking GDS-5 service under the proposed expanded tier.

Although Staff claims that implementation of GFA's proposal would not be straightforward, GFA states that currently any GDS-3 customer can choose to subscribe to GDS-5 service, therefore AIC can already implement GDS-5 for GDS-3 size customers, as long as the customer has a meter that can record daily demand. While Staff further complains that GFA fails to address the impact of its proposal, including rate design, cost allocation, bill impact analysis, customer rate migration, revenue instability and cost analysis, GFA asserts there will be no cost shifting in this case and therefore no cost impact to other customers. GFA contends that instead, it furthers the benefits that GDS-5 provides currently: system costs savings and reliability by having more GDS-5 customers interrupt when the temperature is 25 degrees or less.

Based on the evidence presented in this case, GFA requests that the Commission approve the GDS-5 tariff expansion as proposed in GFA Ex. 1.01G, and if the Commission deems necessary, to delay the implementation to May 1, 2012, and possible limiting the number of customers that can utilize the new tier.

c. Staff Position

Staff states that according to AIC, 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. Staff notes that GFA presented a number of arguments concerning temperature-based pricing for a broader range of customers taking service under the GDS-5 rate, asserting 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. Staff indicates that GFA 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, while 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 states that GFA proposes adding a new tier with a lower fixed charge within the GDS-5 rate for smaller off-peak customers to encourage greater utilization of AIC’s distribution system, but GFA does not at this time 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.

Staff alleges that GFA’s proposal has the potential to set back the attainment of cost-based rates, and believes that implementation of GFA’s proposal would not be as straightforward as GFA suggests. Staff notes that 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. Staff states 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, noting the GDS-5 rates are based costs, reflecting the different impacts that seasonal customers have on fixed and variable costs.

Staff believes that GFA fails to address the impact that its proposal may have on customers, and fails to provide any substantive analysis of the rate or bill impacts of its proposal on AIC, its membership, or on any other customers. Despite proposing entirely new GDS-5 tier provisions for all three Rate Zones, Staff indicates that GFA 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.

Staff is concerned that GFA’s proposed modification is likely to lead to an inequitable assignment of costs among customer classes, because AIC 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, Staff avers that the extent to which this change in rate design will affect AIC’s cost recovery is unknown. To avoid the possibility of revenue erosion, Staff believes a complete analysis of the affected service classifications to determine realignment of class billing determinants would be necessary, which analysis would require assumptions for expected customer migration. In the absence of a thorough analysis, Staff believes 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.

Staff believes that AIC's proposed GDS-5 tariff charges are reasonable. Although under AIC'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), Staff asserts this fact alone does not necessarily render the GDS-5 tariff unreasonable. Staff states 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. Staff opines that GFA's proposal is unsupported, and insufficient analysis has been provided as to the impacts on costs for the customers or revenue for AIC. Staff recommends that the Commission reject GFA's proposal to add an additional tier to GDS-5 across all Rate Zones.

Should the Commission decide to adopt in part GFA's proposal in this proceeding relating to the expansion of the GDS-5 rate class availability, then Staff recommends that the Commission initially limit the number of customers that can utilize the new tier to twelve in order to address the concerns outlined by Staff and AIC. These would be the twelve customers upon whom GFA based its initial revenue erosion analysis that AIC witness Althoff did not challenge. Staff suggests this experimental expansion of the new tier would (1) minimize revenue erosion for AIC; (2) assess the true costs associated with metering and other equipment suited for GDS-3 customers taking service under the GDS-5 rate; and (3) allow both parties to present their finding and analysis in AIC's next rate case.

d. Commission Conclusion

The Commission recognizes on this issue that AIC proposes retaining the GDS-5 temperature based customer class structure in its current form, and proposes no changes to the GDS-5 tariff, while GFA proposes to add an additional tier of customer charges for GDS-3 customers. AIC argues that GFA's proposal overlooks that AIC must properly assess charges to recover the costs necessarily incurred to provide service to its customers, and ignores the cost basis for the respective customer charges incorporated into the GDS-3 and GDS-5 rate designs. AIC contends that were GDS-3 customers allowed to switch to the GDS-5 rate, AIC would be required to install more costly demand metering equipment for those customers and incur related costs; however, those customers would not be assessed the appropriate customer charge. AIC asserts the result would be cross-class subsidization; in that GDS-2 or GDS-3 customers using the seasonal rate would not pay enough to cover the associated costs, which would then have to be borne by other customers.

AIC also notes GFA overlooks the additional, significant potential revenue erosion that would result if eligible GDS-3 customers other than those identified by GFA were to switch to the GDS-5 rate. AIC states it has over 80 other grain drying customers served under the GDS-3 rate structure, and if all were to switch rate classes, the revenue erosion and cost subsidization resulting from the difference in cost between GDS-3 and GDS-5 metering equipment would be significant.

GFA suggests that the Commission consider adding an additional tier to the range of customer charges within the GDS-5 rate for customers of the GDS-3 intermediate size. GFA contends that adding this tier will encourage greater off-peak utilization of the AIC distribution system. GFA also proposes an additional tier for customers having a MDCQ of greater than 200 and less than 1,000 therms – which is the eligibility requirement for a GDS-3 customer. GFA notes the proposal would also replicate the GDS-3 Customer Charges for this tier.

The Commission notes that Staff suggests that AIC's proposed GDS-5 tariff charges are reasonable, although under AIC’s 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 due to high monthly fixed charges. Staff asserts this fact alone does not necessarily render the GDS-5 tariff unreasonable.

Staff suggests that should the Commission consider adopting GFA’s proposal in this proceeding, that the Commission initially limit the number of customers that can utilize the new tier to 12 in order to address the concerns outlined by Staff and AIC. Staff indicates these would be the 12 customers upon whom GFA based its initial revenue erosion analysis. Staff suggests this experimental expansion of the new tier would minimize revenue erosion, assess the true costs associated with metering and other equipment suited for GDS-3 customers taking service under the GDS-5 rate, and allow both parties to present their finding and analysis in AIC’s next rate case.

The Commission believes that based on the evidence presented by in this proceeding, there is a possibility of benefit to AIC from adoption of the tariff suggested by GFA, including system costs savings and in system reliability. The Commission also recognizes that there are certain risks inherent in its adoption, including revenue erosion to AIC and possible cross-class subsidization.

The Commission will, therefore, approve the GDS-5 tariff expansion as proposed in GFA Ex. 1.01G; however, the Commission will delay the implementation of the tariff to May 1, 2012. The Commission also agrees with Staff's suggestion that the use of this new tariff will be limited to the 12 customers identified by GFA in its initial revenue erosion analysis.

Because the Commission is authorizing this tariff expansion on a limited, experimental basis, the Commission believes that to continue this process, and in order to contemplate continuation of the tariff or further expansion, evidence must be presented in AIC's next rate case that demonstrates that the expanded tariff: improves system costs savings and reliability by having more GDS-5 customers interrupt when the temperature is 25 degrees or less; minimizes revenue erosion; and properly assesses the costs associated with metering and other equipment for GDS-3 customers taking service under the GDS-5 rate.

X. PROPOSED RIDERS/TARIFF CHANGES

A. Resolved Issues

1. Pension Benefits Rider

In the interest of narrowing the number of issues in the case, AIC has withdrawn its request for a pension rider.

2. Uncollectibles Rider

Staff recommends that the Commission order AIC 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 calculates the percentage of uncollectibles related to delivery services using the net write-off method for each Rate Zone. AIC rejects Staff's proposal to switch to the net write-off method and the calculation of an individual percentage for each Rate Zone. These issues are addressed earlier in the section of the Order regarding uncollectibles expense.

Should the Commission agree with Staff's recommendation to adopt a net write off methodology, the parties note that tariff changes are necessary for Rider GUA. As AIC witness Jones explains, presently, Rider GUA states that the incremental uncollectible adjustment amounts reflect the difference between the actual uncollectible expense amounts for Account 904, and the uncollectible amounts included in the utility's rates that were in effect for such reporting year. If a switch is made, pursuant to Section 19-145(a), AIC and Staff indicate the switch must 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. Assuming this docket concludes in January 2012, the parties state the first full calendar year after new rates are approved would be 2013. Thus, AIC and Staff note the first Rider GUA incremental adjustment amounts reflecting a net write-off basis would be in May 2014 for factors effective from June 2014 through May 2015, reflecting the difference between net write-offs and the amount included in rates for 2013. AIC and Staff indicate a paragraph should be added to the "Incremental Uncollectible Adjustment" sections of ~~both~~ Rider GUA that addresses the switch to the net write-off method for the 2013 reporting year, and subsequent reporting years. Additional relatively minor tariff language changes would be needed to clarify that through the 2012 reporting year, Account 904 will be used, but that starting with the 2013 reporting year, a net write-off method will be used. AIC and Staff assert no party has opposed these changes. The Commission notes that earlier in this Order it did adopt the net write-off method for uncollectibles expense; therefore the Commission agrees that tariff changes are necessary for Rider GUA. The Commission directs AIC to adopt the changes discussed above, as agreed to by the parties.

B. Contested Issues

1. Rider TBS - Transportation Banking Service

a. AIC Position

In response to concerns raised in AIC's prior rate case regarding AIC's gas transportation banking service, AIC has submitted alternative tariffs setting forth an unbundled, subscribable banking service - Rider TBS. AIC indicates its proposal allows transportation customers to individually choose the bank service level, up to 15 days of bank, desired by the customer. As such, AIC asserts it provides transportation banking customers' greater banking service flexibility and is a reasonable solution to the concerns that arose in the last rate case, and therefore should be approved.

AIC notes, however, that Staff proposes to modify AIC's proposals by replacing much of the Rider TBS tariff with Nicor tariff banking provisions. AIC asserts that Staff's proposal to apply Nicor tariff provisions to AIC, however, does not take into account AIC's operational circumstances. AIC notes that Staff admits there are operational differences between AIC and Nicor, and claims that Staff has failed to explain why Nicor provisions should nevertheless be applied to AIC. For this reason alone Staff's proposed modification to Rider TBS should be rejected, however AIC claims further that Staff's proposed modifications will cause AIC to incur increased costs, which will be borne by sales customers, and expose AIC to operational difficulties.

In Docket Nos. 07-0585 et al. (Cons.) AIC notes its legacy utilities were ordered to implement a gas transportation banking program, known as Rider T, which became effective in 2008. In AIC's last rate case, Docket Nos. 09-0306 et al. (Cons.), AIC states there was substantial disagreement between AIC, Staff, and several gas marketers regarding whether the total bank size should be significantly expanded. Ultimately, AIC notes the Commission did not order any changes to the banking provisions of Rider T, however, the Commission did direct that workshops be held prior to AIC's next gas rate cases for the purpose of discussing alternatives to AIC's current banking terms and conditions. AIC indicates the Commission required that AIC submit a tariff implementing the Nicor method for determining bank size, but allowed AIC to offer an alternative.

AIC states that workshops were held on November 17, 2010 and December 13, 2010 at the Commission's offices in Springfield, Illinois, and based on the input received at the workshops, AIC agreed to offer a subscribable bank, where transportation customers could select any number of days, from 0 to 22 (later corrected to 0 to 15), that when multiplied by their MDCQ would determine their bank size.

As required by the Commission in Docket Nos. 09-0306 et al. (Cons.), AIC provided in its initial filing tariffs which contained the banking provisions resulting from the use of the Nicor and Peoples/North Shore models. AIC states it calculated the number of days of bank that would result from the application of the Nicor and Peoples/North Shore methods to its storage resources, which was 29 and 22 days, respectively. AIC's proposed tariff utilized the Nicor method, the more conservative of the two, however, AIC asserts that the tariff utilizing the Nicor method is not workable for AIC's system.

AIC indicates that to address concerns raised in the workshops, and as authorized by the Commission in Docket Nos. 09-0306 et al. (Cons.), AIC submitted alternative tariffs setting forth unbundled, subscribable banking service, presented in AIC's tariffs for Rider TBS. AIC states its proposal also provides for the allocation of on-system storage costs to Rider T customers, unsubscribed bank cost recovery language in Rider S, an election process that allows Rider T customers to subscribe to their preferred bank size between 0 and 15 days times their MDCQ limit for individual bank size as part of the Bank Election Process, and other implementation and service management provisions. AIC's asserts its proposal provides transportation customers with the flexibility to individually choose the bank service level desired by the customer.

As part of AIC's proposal, AIC notes it proposes a banking service limit ("BSL") of 10 times the total aggregate MDCQ bank capacity of transportation customers, which bank capacity represents 21% of the total nameplate capacity of AIC's on-system storage. AIC argues its proposed allotment of storage capacity is reasonable because AIC's transportation service does not impose on its users the requirement to bank gas in the summer and empty banked gas in the winter as required by the Nicor and Peoples/North Shore tariff. AIC avers that to operate its on-system storage fields in the manner necessary to meet sales customers' peak day needs and consistent with good engineering practice, AIC must cycle on-system storage to the maximum extent possible.

AIC notes it also proposes to recover 50% of storage costs through a Deliverability Charge and 50% through a Capacity Charge in Rider TBS. AIC claims a proper allocation of on-system storage costs includes a deliverability component reflecting a transportation customer's access to their banks on a peak day and a bank capacity component reflecting the overall size of a customer's bank. Stated differently, AIC states there is a cost associated with a customer's daily access to a bank and a cost associated with the size of the customer's bank. AIC notes this concept has been termed the "Equitable Method" for developing storage rates. See e.g., Tennessee Gas Pipeline Company, 56 FPC 120, 160 (1976), reaffirmed by FERC Opinions, Orders and Notices in Equitable Gas Company, Docket CP85-876-000 (1986). AIC opines that the "Equitable Method" allocates 50% of fixed storage costs to peak delivery rights and 50% of fixed storage costs to overall storage capacity, also called maximum storage volume.

In rebuttal, AIC notes its Nicor method calculation was corrected, producing a bank limit for each individual customer of 15 times their MDCQ (instead of 22 times) and a proportional share of AIC's on-system storage of 8.22 billion cubic feet ("Bcf") (32%). In light of the correction, AIC proposes adoption of an individual bank limit of 15 days, with the BSL remaining at 10 days. AIC states unsubscribed capacity will be offered to those customers wanting more than 15 days, so customers who want additional storage capacity may receive more than 15 days under the election process. Should the Commission adopt the 15 days of bank for the overall BSL, as calculated under the Nicor method, AIC recommends that the Commission reject the rest of Mr. Sackett's proposed Nicor-based tariff modifications to AIC's Rider TBS.

AIC states that Staff witness Sackett takes the position that Rider TBS should be approved, but with modifications, however AIC asserts that these proposed modifications so materially alter AIC's Rider TBS proposal as to essentially gut AIC's proposal. Further, AIC claims Staff's modifications affect the collective sales customers' rights to storage, and that sales customers are the backstop for transportation customers and are adversely impacted by Staff's proposal, despite the fact that Staff agrees sales and transportation customers should be fairly assigned the same rights.

Staff proposes modifications to AIC's proposal based on what Staff calls the "Nicor method," however, AIC avers there is a distinction between the "Nicor method," utilized in past Nicor rate proceedings to determine the number of days of bank, and the numerous other Nicor transportation tariff provisions that Staff seeks to impose on AIC. AIC claims Staff appears to be advocating that the Commission approve not just the Nicor method for establishing days of bank, but apply to AIC certain Nicor tariff provisions as well. In particular, AIC notes Staff seeks to impose the following other Nicor transportation tariff provisions on AIC in this case: an injection target provision, the 2.2% of customer bank access on a Critical Day ("CD") provision, and the on-system storage cost allocation and Rider TBS rate derivation. AIC states that Staff's application of the Nicor method based on its proportionality position is improper. Additionally, because Staff does not establish that AIC's and Nicor's systems are operationally comparable, AIC claims that Staff fails to establish that application of Nicor's tariff provisions is appropriate for AIC.

AIC notes the concept of "comparability" in establishing utility rates and tariffs with reference to other utilities is well established under Illinois law, stating the Commission should not "afford any appreciable weight or reliance on" a comparison of utility rates, costs or tariffs to those of entities not shown to be "comparable." See Antioch Milling Co. v. Public Serv. Co. of N. Ill., 4 Ill.2d 200, 210 (1954) (holding that evidence on the rates charged by other utilities should be disregarded where the party proffering the evidence failed to show "that the [utilities'] conditions of service were comparable"); Citizens Util. Co. of Ill., Docket No. 94-0481, 1995 WL 612576, *16-20 (Sept. 13, 1995) (declining to rely on a Staff depreciation analysis comparing utility to other utilities, where no showing of comparability to those utilities was made). Thus, AIC asserts that specific operational differences between AIC and Nicor should be considered before applying the Nicor method and tariff provisions. AIC argues that no two storage fields operate in the same manner, stating that their size, geology, weather, proximity to pipelines among other factors make their operation distinct from each other.

Yet AIC opines that Staff's proposals implicitly assume they do all operate the same way. Further, AIC avers that no two distribution systems are the same, as pressure, distance from the pipeline, size of the pipe, and end use load characteristics all play a vital part in managing the operations of the systems. AIC argues these differences are not accounted for by Staff. AIC contends that Staff is advocating a one-size-fits all approach to transportation banking for utilities that are not the same "size", operationally speaking.

AIC states that the evidence shows that Nicor provides service to over two million natural gas customers in a geographic area roughly half the size of AIC's service territory, which AIC notes serves less than 900,000 customers. AIC asserts that Nicor's transmission and distribution networks have a much greater degree of interconnection and integration, offering greater flexibility in moving gas across its entire system than AIC's. AIC indicates that Nicor's Chicago area service territory is also home to one of the largest natural gas transmission hubs, which is another material difference between the Nicor and AIC systems. AIC states that Staff witness Sackett agreed taking gas from the Chicago hub presented operational difference for customers taking gas in the Chicago area as compared to downstate customers. Further, AIC opines that Nicor owns and operates eight storage fields with an annual capacity of nearly 135 Bcf while AIC owns and operates 12 fields with a capacity of only 25 Bcf.

In contrast, AIC states that six of its smaller storage fields are largely constrained by the distribution system to serve only a small subset of its gas customers, while many of AIC's customers are served by distribution systems with no access to any AIC storage field. Further, AIC states that approximately 80% of its supply is provided by two pipelines, Natural Gas Pipeline ("NGPL") and Panhandle Eastern PipeLine Company ("PEPL"), which places AIC at a significant risk if either of these pipelines fail or have significant capacity restrictions. AIC notes that Mr. Sackett agreed the AIC legacy distribution systems were not planned as one system, that each was built to provide service needs in its service areas only, that the systems are not integrated, and that there are captive systems. AIC states these operational differences hamper AIC's ability to move gas supplies.

AIC asserts that its proposed Rider TBS banking provisions take into account AIC's own operational circumstances, while Staff has failed to either (1) demonstrate a comparability between AIC's operations and Nicor's, or (2) explain why Nicor provisions should nevertheless be applied to AIC despite the differences.

AIC also recommends the Commission reject Staff's proposal that Rider TBS should be modified to reflect CD withdrawal rights (2.2% of the transportation customer's bank limit) set for all transportation customers based on their subscribed storage capacity. AIC recommends the Commission maintain CD withdrawal rights as proposed by AIC, which is the level approved by the Commission in the last two AIC rate proceedings. As Mr. Eggers explained, Staff's proposal provides transportation customers with greater access to banks on a CD than a normal day, which defeats the purpose of declaring a CD. Further, to provide transportation customers these rights on a CD, AIC asserts it would be forced to purchase additional leased storage and pipeline capacity assets at a significant cost to sales customers, as whatever additional resources designated to be used to serve transportation customers must be replaced to continue to serve its sales customers, who were the previous beneficiaries of the transferred resources. Assuming the additional resources would be contracted on PEPL, one of AIC's largest interstate pipeline suppliers, AIC claims these additional resources would cost approximately $8 million per year.

AIC notes that Mr. Sackett admits the 2.2% CD withdrawal rights works a perverse outcome when applied to his proposed number of bank days, since on a CD, it would allow the transportation customer to take 32% of its bank (2.2% x 15 days), at a time when the system's operational integrity is at stake. Under this scenario, the sales customers would have the remaining 68%. AIC states that Mr. Sackett admitted, if transportation customers only took 20% and sales customers took 40%, sales customers would be responsible for the costs associated with the difference, since any portion of that bank that is not utilized by transportation customers, gets picked up by sales customers.

AIC asserts that Staff does not dispute that AIC could be required to incur additional cost, but rather claims that it is unknown whether AIC would have to incur costs to obtain additional resources and AIC would need to re-evaluate its peak day portfolio if the Commission ordered them to offer proportional rights on the peak day. AIC notes that Staff acknowledges that if AIC did require more assets, sales customers would pay less than they currently do for on-system storage and more for off-system assets, but that the net effect is unknown. AIC claims the uncertainty of the cost impacts of Mr. Sackett's proposal is, by itself, a reason to reject his proposal, citing <u>Abbott Laboratories, Inc. v. Illinois Commerce Comm'n</u>, 289 Ill. App. 3d 705, 712 (1st Dist. 1997), where the Court held that operational integrity of public utility should not be compromised by forcing utility to incur costs to obtain gas as a result of transportation customer actions.

AIC notes that Staff recommends giving transportation customers proportional maximum storage capacity based on adoption of Nicor tariff provisions, which would raise the BSL from AIC's proposed level of 5.48 Bcf to 8.22 Bcf. AIC asserts this proposal should be rejected, as the bank service limit under AIC's method is appropriate because the reason for AIC's BSL is to allow AIC to fill and cycle its on-system storage resources on a consistent schedule that protects the operational integrity of its fields. AIC states that aquifer storage field operations require inventory minimums, and notes that AIC must follow certain injection and withdrawal parameters to maintain the integrity of the storage fields. AIC claims that the 90% fill requirement in Staff's proposal provides only a minor incentive for transportation customers to fill its bank, as the only penalty is slightly reduced CD withdrawal rights. Since AIC has not called a system wide CD in over 10 years, AIC opines that a transportation customer would have very little incentive to fill their bank to the levels required to maintain the operational characteristics of its storage fields.

AIC states there are two key issues with the tariff aggregate BSL proposed by Staff, the first of which is a system integrity issue. AIC notes that Staff's proposal grants transportation customers up to 8.22 Bcf of capacity, and since CD rights are a percentage of bank capacity, this automatically places a much larger aggregate obligation to serve CD bank withdrawals. AIC's proposed BSL is an important limit to this increase to CD obligations. AIC notes the second issue is a stranded asset issue, which risk stems from the variability of CD rights from year to year that is inherent to Staff's proposal. AIC argues that Staff's proposal allows transportation customers to elect from very little to 8.22 Bcf of bank capacity, with AIC expecting in years with very good storage economics the entire capacity to be elected, while in with very poor storage economics, capacity of 2 or 3 Bcf might be elected. AIC notes that since CD rights are directly tied to bank capacity elected, the amount of gas that AIC is obligated to plan for will change year to year, which places AIC at risk of acquiring assets to meet its obligations in years with high bank elections that are then stranded in a following year with low bank elections.

While Staff proposes implementing a fall injection target like that used by Nicor Gas, Peoples and North Shore Gas, AIC avers that having a fall injection target is not enough to protect the integrity of storage fields, particularly if the target has very limited consequences if missed. AIC believes that, for its operations, an injection target is meaningless without a withdrawal target. AIC states it will make up any difference from planned injections and withdrawals that result from the actions or inactions of transportation customers with sales customer activity. Under AIC's current tariffs, sales customer gas is used to facilitate the necessary injections and withdrawals to maintain field integrity, and therefore AIC requires no bank fill or empty targets under its proposed BSL.

AIC asserts that its daily balancing service effectively utilizes both capacity (bank size) and deliverability, and this flexibility in AIC's bank service to cover daily imbalances significantly reduces the amount of gas that a transportation customer might have to cashout. AIC states its bank service allows injections in the winter and withdrawals in the summer and provides a 20% balancing tolerance before cashing out. AIC notes any balancing before cashout should be a base rate recovery issue because it is part of the tariff bank service (base rates) and any balancing done by cashout is a PGA recovery issue. Given the cashout premiums paid by transportation customers, AIC claims it is clear that the balancing provided by AIC offers a tangible benefit to transportation customers, and its proposal appropriately allocates costs to transportation customers based on the service provided to them.

AIC notes Staff also takes the position that if the Commission rejects the 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, the Commission should allocate those costs based on 20% of the average historical peak DCN during the past two years. AIC disagrees and contends transportation customers should be allocated costs based on the contracted service level between it and the customer, the MDCQ. AIC states each transportation customer has the right to 20% of DCN on a CD and each customer can nominate their entire MDCQ, which gives each transportation customer the right to 20% of their MDCQ on a CD. AIC states it must plan for the full utilization of the rights it affords to customers and retain assets accordingly, therefore, AIC's allocation based on MDCQ is appropriate and should be adopted by the Commission. Further, AIC notes that Mr. Sackett's concern that AIC's proposal will "drive customers away" from transportation is completely unsupported by any study or analysis on his part, noting that no quantification of the cost differences has been provided, nor has any analysis been done of the impact of differences in costs on the economics of a customer's decision to take transportation service.

AIC indicates that IIEC has three concerns with AIC's banking provisions. AIC states that IIEC does not agree with maintaining the 22 times MDCQ allocation following the corrected bank days calculation, rejects AIC's proposed 10-day BSL and recommends that each transportation customer be allowed to subscribe to a maximum 15 days of storage, and lastly takes issue with AIC's proposed cost allocation methodology.

AIC notes that it will accept, a maximum of 15 days times MDCQ for an individual customers' subscribable bank election as Mr. Gorman suggests, provided the 10 day BSL is not exceeded. For the reasons discussed above with respect to Staff's position, AIC notes it supports the BSL at 5.482 Bcf which is based on 10 days of bank, and recommends the Commission adopt this position. AIC also recommends that the Commission reject IIEC's position on the proposed cost allocation methodology, claiming that AIC's proposal is reasonable and should be adopted.

AIC indicates that IIEC appears to find this revised proposal more acceptable; however IIEC continues to oppose any aggregate limit on transportation customers' storage capacity. While IIEC asserts that AIC has not demonstrated or claimed any inability to meet the 15 day limit, AIC contends that it has shown that raising the BSL would pose system integrity and stranded asset concerns. IIEC does not address these concerns.

AIC states that Staff witness Jones recommended that the formula to calculate the Unsubscribed Bank Capacity Charge ("UBCC") and language providing for an annual reconciliation be included in Rider S - System Gas Service. AIC accepted the recommendations to include the formula to calculate the UBCC and language that provides for an annual reconciliation in a section that AIC added to Rider S – System Gas Service regarding its proposed UBCC.

AIC suggests the disputes between Staff, IIEC, and AIC over transportation banking provisions are rooted in complex issues of gas storage operation, transportation customer behavior, and accounting, however, the choice is simply whether the Commission favors increasing the rights of transportation customers at the expense of sales customers. AIC suggests the Commission either agrees that sales customers' costs and benefits should be at risk or they should not.

AIC indicates that Staff's Initial Brief acknowledges the policy choice presented between transportation customers and sales customers, noting that the expansion of transportation customer rights would have an impact on sales customers. AIC notes that with respect to CD withdrawal rights, Staff witness Sackett admitted that AIC might have to add more capacity to make that capacity available to transportation customers on a CD, and that sales customers would pick up the tab for any expansions to off-system storage and capacity. AIC suggests that this also raises a cost causation issue, if granting rights to transportation customers is imposing costs on sales customers, why are transportation customers not paying those costs. Given that sales customers include mostly residential and other small customers, it is AIC's position that the Commission, as a policy matter, should not impose costs on the sales customers when they are not responsible for those costs and where other options are available.

AIC notes that Staff in its Initial Brief asserts AIC has not proven that AIC and Nicor are sufficiently operationally different to make the Nicor method inappropriate to apply to AIC, however AIC asserts it is Staff's burden on this issue, as proponents of the modifications that would impose Nicor tariff provisions on AIC, citing Citizens Util. Co. of Ill., Docket No. 94-0481, 1995 WL 612576, *16-20 (Sept. 13, 1995). AIC argues Staff has not even attempted to prove comparability between Nicor and AIC, while AIC has shown the differences between the two systems are significant.

While Staff acknowledges that operational differences exist between AIC's Rate Zones, as they do between AIC and Nicor, Staff notes that AIC has proposed uniform banking provisions across its Rate Zones. AIC indicates that now that AIC has merged, and is moving to operate in an integrated manner, for example by establishing a single PGA, it is appropriate for AIC to have uniform banking provisions. Further, AIC avers that Staff's assertion does not answer the question why, even if AIC does have operational differences between Rate Zones, Nicor tariff provisions are appropriate for some or all of AIC's Rate Zones.

While Staff also asserts that AIC is ignoring the concept of gas displacement, AIC contends that Staff's use of the concept of displacement is wrong and not how the concept is usually applied. AIC states that gas deliveries utilizing the principle of displacement are typically of equal volumes over a short period of time. AIC alleges Staff improperly extends this concept to seasonal withdrawal quantities over many months, applying the displacement concept in its simplest form—10 units in, 10 units out.

In addition, even accepting that sales and transportation gas are mixed in on-system storage due to displacement, AIC opines there is the problem of withdrawing gas from storage fields without transportation customers withdrawing from their banks. AIC notes that its transportation customers will withdraw from their banks when it is economically beneficial to do so, while they will not withdraw when it is not economical. If sales customer's gas must be used to withdraw when transportation customers do not, AIC indicates the sales customer group will be forced to withdraw gas when uneconomical.

Regarding cost allocation, AIC notes that Staff in its Initial Brief claims, absent any credible evidentiary support, that AIC's proposal would allocate a significant portion of costs to the first day of bank, which Staff asserts is a problem because it might cause some GDS-4 customers to select no bank or cause some smaller customers to go back to sales service. AIC asserts that Staff does not explain why allocation of costs to the first day of bank is improper if that is in fact reflective of cost causation, while AIC notes it assigns the costs for the first day of bank because it affords peak day access. AIC opines it also incurs costs related to providing balancing provisions afforded by electing a bank, and as there is a cost to make the banking service available that AIC incurs no matter the bank size, allocating costs to the first day of bank is appropriate. While Staff is also critical of what it sees as a mismatch between tariff rights based on DCN and charges based on MDCQ, AIC alleges Staff ignores a fundamental point, which is that charges must be based on MDCQ, even if tariff peak day's rights are based on DCN. Because there is a cost incurred in simply making the system (in this case in the form of peak day access rights) available, AIC indicates it is appropriate to allocate transportation charges on the basis of MDCQ.

With respect to interim rates, in effect between the conclusion of this case and the effective date of Rider TBS of May 1, 2012, AIC notes it proposes to use the Equitable Method based on existing transportation customer MDCQs on November 1, 2010. Although Staff believes that interim base rates should be determined in the manner that the Commission ordered in the previous rate case for those three months, AIC views that allocation as inappropriate. AIC states that other rates become effective on the date of the Commission's orders, therefore AIC recommends its proposed storage cost rates take effect with the order in this case.

AIC notes that IIEC also takes issue with the use of the Equitable Method, claiming this method is primarily used by FERC to allocate costs between pipeline contract storage service customers and transportation customers, and not for the allocation of storage costs between two groups of customers such as Sales and Transportation customers. AIC asserts, however, that the Equitable Method is appropriate for use in the allocation of costs for any storage field, regardless of regulatory domain, and is appropriate here considering the balancing service and electable capacity offered as part of the proposed banking provisions. Since deliverability and capacity are not functionally tied in AIC's banking service, AIC claims these two features need to have costs allocated separately. AIC asserts the Equitable Method is an allocation method that appropriately allocates costs to both the deliverability component and the capacity component.

While IIEC also argues the Equitable Method AIC proposes to use overstates both the "maximum" and the "probable" deliverability used by transportation customers on a peak day, AIC asserts that its customers should pay for the service they have available to them. AIC notes that IIEC is incorrect when it claims daily balancing transportation customers cannot withdraw 20% of their MDCQ and monthly balanced Transportation customers cannot withdraw 50% of their MDCQ on a peak day. AIC states that a daily balanced customer can nominate their entire MDCQ, and if they were to use more than their MDCQ, they would have access to up to 20% of their MDCQ from their banks, while monthly balanced customers can use up to 50% of their MDCQ on a CD. In fact, AIC claims it must deliver volumes in excess of the 20% of DCN if the customer elects to under-deliver and purchase gas from the sales customers, so the true physical access to the system on any day is greater than 20% MDCQ for Daily balanced customers and 50% for Monthly balanced customers.

b. Staff Position

Staff notes that AIC's customers all take service under either Rider S or Rider T, with Rider S customers purchasing gas commodity exclusively from AIC at the PGA price each month and are referred to as sales customers, while Rider T customers purchase gas commodity from suppliers and are referred to as transportation customers. Staff states that transportation customers nominate their pipeline deliveries separately from the utility, which is the agent for sales customers, and 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.

During AIC's last two rate cases, Staff indicates that transportation service has taken its current form under Rider T. Staff states that one issue that it raised in the 2009 rate case concerned the level of access that transportation customers had to AIC's on-system storage. In particular, Staff argued that it should be proportional to system storage capacity, and although the Commission declined to make any changes in that docket, ordered that AIC and Staff participate in a workshop process. Staff states the Commission also required that AIC provide tariffs implementing either the Nicor or Peoples method.

Staff notes that AIC indicated it preferred the Nicor banking provisions rather than those of Peoples and North Shore Gas. Staff claims the Nicor method has three integrated features: subscribable peak day storage withdrawal rights, seasonal storage, and storage costs. Staff states 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. Staff avers 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. Staff notes 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, with storage costs recovered through a charge on storage capacity.

Staff states that AIC opposes the premise of proportional storage rights. Staff asserts that AIC has historically opposed any banks for transportation customers, and in 2007 proposed to eliminate the banks of its legacy transportation customers and to implement a transportation service devoid of banks. Staff argues that AIC's basic view of transportation customers as second-class customers without any inherent rights to storage is evident from AIC's continued resistance to equitable access to peak day deliverability and seasonal storage capacity.

Staff asserts that AIC currently provides rights that are below the proportional level, and notes the expansion of these rights would have an impact on sales customers. Staff notes the question is whether such impacts are fair and appropriate given the current state of affairs, indicating that AIC'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.

While AIC charges that Staff has not established that AIC's system is "operationally comparable" to that of Nicor Gas, Staff complains that AIC never defines this concept on the record nor proves that the two systems are sufficiently different as to make the Nicor method inappropriate for AIC's systems. In surrebuttal, Staff states that AIC describes system differences that it believes distinguishes it from Nicor Gas; however Staff notes some of these same differences exist between the three Rate Zones, yet AIC has proposed uniform maximum storage capacity and uniform CD withdrawal rights across the Rate Zones. While AIC complains that Staff's proposal to apply the Nicor method to AIC's system as a "one-size-fits-all" method, Staff argues its proposal to apply the Nicor method to AIC is "AIC-specific."

Staff states that AIC proposes a uniform average bank level for all three Rate Zones even though the storage in those systems differ considerably. Under AIC's surrebuttal position, 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, therefore Staff argues that AIC's own proposal indicates that AIC's system is more robust than it suggests by arguing it is not operationally comparable with Nicor's system.

Staff also complains that several of AIC's arguments ignore the gas operational concept of displacement, which is defined by the American Gas Association ("AGA") 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."

Staff notes that AIC reflects a willingness in its arguments to ignore displacements, including in its treatment of specific gas in specific assets as belonging to a specific class of customers. While AIC claims that devoting 32% of the working capacity of a storage field to a customer group that may choose not to withdraw during the winter season presents significant operational difficulties, Staff suggests AIC implies that transportation customers "control" those assets.

While AIC claims that on-system storage capacity is "devoted" to transportation customers, Staff states this contradicts an earlier statement that only sales gas goes into those fields. Staff asserts that AIC states that it currently fills on-system storage with sales customers' gas and puts transportation customers' gas in banks elsewhere within the system, although Staff claims this is just an accounting convention rather than a physical fact, noting that AIC witness Eggers explained that AIC's current storage resources provide transportation customers the option to bank as they see fit within the 10 day 5.482 Bcf of BSL.

Although AIC avers 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, Staff claims that since transportation customers do not really control gas in on-system assets, this is really not an issue.

Staff states that under the Nicor method, transportation customers are able to select the amount of storage capacity from any level from one times MDCQ to the maximum amount determined. Staff indicates that customers are not able to select no bank, and this subscribable feature enables transportation customers to choose the amount of storage that best suits their needs.

Staff witness Sackett also explains that charges are based on the total cost of storage per unit of storage capacity, and to determine the storage charges, the total cost of on-system storage is divided by the capacity of that storage. Staff notes that a transportation customer's charges for storage equal the customer's Bank Limit multiplied by the storage charge.

Staff states that AIC asserts that such an expansion of rights would force AIC to purchase additional storage capacity, and that Staff's proposal grants transportation customers more deliverability from storage on a CD than on a non-CD. Staff responded to these arguments by pointing out that AIC's current tariffs provide sales customers with a disproportionate peak day access to its storage assets, and Staff claims correcting this distortion allows transportation customers their fair share of those assets while requiring them to pay proportionally for them.

Staff avers that AIC can also increase its peak day resources if necessary, noting that AIC originally proposed to eliminate at least one off-system storage asset from its portfolio. Staff notes that AIC has proposed to retain at least some of these assets because of Staff's proposal to give transportation customers equal rights to storage as sales customers. Since each asset has both maximum storage capacity and peak day deliverability components to it, Staff states AIC was planning on releasing both peak day deliverability and maximum storage capacity.

Staff states that AIC proposes to provide an unbundled storage bank for transportation customers under a new service called Rider TBS, under which AIC proposes to only guarantee 10 days of bank to its customers as a group. Staff notes that AIC indicates that because many transportation customers do not fully utilize their banks (i.e., they do not completely fill their banks), it can offer, but not guarantee, individual customers more than 10 days, using 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.

Staff notes that under AIC'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 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. Staff states that AIC asserts that monthly balanced customers must, by definition, use storage assets to stay in balance, so they should be required to pay for at least 5 days.

AIC 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, and Staff agrees with AIC's proposal for Rider TBS including a subscribable bank and the increased injection rights during the summer, but disagrees with AIC on the total size of that bank available to transportation customers.

Staff notes that the current peak day withdrawal rights, which are independent of the bank capacity, were determined in AIC's 2007 rate case, and were originally proposed by Staff in response to AIC's proposal to eliminate all bank and any associated peak day withdrawal rights. Staff states it did not attempt to make the withdrawal rights proportional to Sales customers' withdrawal rights at that time. In its 2009 rate case, AIC proposed to recover storage costs from all transportation customers based on the peak-day withdrawal rights of daily-balanced customers, and because AIC did not propose to recover the costs for monthly-balanced customers based on their relatively liberal withdrawal rights, Staff indicates there was no need to correct this discrepancy until the present case.

Staff opines that 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 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. Using the Nicor method, Staff notes AIC'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 CD withdrawal rights of 2.2% of the transportation customer's Bank Limit, which Staff recommends that the Commission approve in this case.

Staff states that AIC proposes in Rider TBS to limit transportation customers as a group to a BSL, which AIC defines as the MDCQ of all Rider T customers as of November 1, 2010, multiplied by 10, or 5.48 Bcf. Staff notes this level is less than the proportional level determined under the Nicor method. 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.

Staff notes that AIC 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, and suggests other divisors might be more appropriate, such as “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.” Staff avers that Peoples 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 and 11-0282 (Cons.)), and neither Peoples, North Shore, or Nicor have indicated the need for an “operational link” for their allocator and have been able to operate their systems competently.

Staff suggests that using relative peak day demand makes sense as it is the only Commission-approved method for proportional capacity allocation, and AIC uses relative peak day demand to allocate banks to individual transportation customers. Since AIC itself has used this method for allocating banks amongst transportation customers for decades, Staff suggests it is only logical to use this divisor to allocate proportional annual capacity.

Consistent with the Nicor approach, Staff proposes that the BSL be set at 8.22 Bcf, which is equivalent to 15 days of bank, as well as a single fall injection target, like the one used by Nicor, as appropriate for AIC’s transportation customers. Staff suggests this target should be set at the average maximum level that AIC has filled its on-system storage for the past five years.

AIC states that if it were to give proportional storage rights, this would require “some measure of cycling requirements,” however Staff suggests that because of displacement, all gas can be cycled from the fields even if transportation customers do not withdraw it from their banks. Staff notes one option to provide AIC with a tool to handle the 15 day bank allocation to transportation customers is to implement a fall target in this docket, and if this target is not effective, AIC has the option of filing a 45-day filing or correcting it in the next rate case.

Even if the total storage capacity of individual customers or transportation customers as a group is limited by the Commission to AIC’s proposed BSL of 5.2 Bcf, Staff argues the storage cost allocation and peak day rights determined under the Nicor method are still relevant, and the Nicor method of tying the peak day withdrawal and total bank capacity level to a lower BSL is still appropriate.

In direct testimony, Staff witness Jones recommended changes to the language in AIC’s proposed Rider TBS predicated on a BSL that could change annually. Staff notes 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. AIC clarified that AIC's position is that the BSL will be fixed between rate proceedings. If the TBS approved by the Commission is structured such that the BSL and its attendant rates remain fixed between rate proceedings, Staff states Ms. Jones' recommended changes will not be necessary; however, if the Commission approves a TBS such that the BSL and its attendant rates would fluctuate between rate proceedings, Ms. Jones' recommended changes should also be approved.

To set rates for storage, Staff indicates that AIC proposes what it calls the Equitable Method, which uses one of the FERC approaches to rate-setting for storage services. Staff notes this method assesses 50% of fixed costs to total storage capacity and 50% to peak day delivery rights. AIC states its current cost allocation 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 AIC's system storage fields. Staff notes this method is not appropriate when the customer's maximum storage quantity varies based on the customer's choice.

While AIC'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, Staff asserts that 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 avers that AIC's method would allocate a significant portion of costs to the first day of bank, which could result in negative impacts. Staff alleges that one possible impact could be to drive at some GDS-4 customers, who had that option, to select no bank in order to avoid the high initial bank charges, noting that AIC has already stated that it does not expect electric generators to purchase banks at all because they seldom use the ones they currently have. Another concern Staff has is that AIC's cost allocation proposal, when combined with AIC's proposed requirement for monthly-balanced customers to subscribe to at least 5 days of bank, could drive some of these smaller customers back to sales service, which would reduce the benefits now enjoyed under Transportation service. Staff indicates this migration would be based on the fact that transportation service would no longer be economical. Staff notes that Ameren Ex. 34.1 confirms that AIC'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 opines that storage costs should reflect the cost of services and not the extra benefit received. While AIC claims that it incurs higher costs in balancing monthly-balanced customers, Staff indicates it has not shown that this is the case.

Staff states that in the 2007 rate case, the Commission ordered AIC to institute a system-wide monthly-balanced transportation service directed at smaller volume transportation customers, and since that time, transportation service to GDS-2 and GDS-3 customers has grown from about 1,100 customers to about 2,100 customers currently. Staff asserts this growth reflects the appeal of this monthly-balanced program and its tariff parameters, however the significant increase in the storage costs allocated to monthly-balanced customers may arbitrarily make transportation service uneconomical for smaller customers.

Staff notes that AIC 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. While AIC sees this Nicor method charge as a charge per therm of maximum storage capacity, Staff avers 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.

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, which 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. Staff asserts that doubling the proposed capacity charge and linking the CD withdrawal right with the storage capacity eliminates the need for a separate capacity-based portion of that charge. Because of the high percentage of storage costs allocated to the first day of bank under AIC'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.

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 CD withdrawal rights which remain at 20% of DCN as opposed to the 20% of MDCQ that AIC proposes. Staff claims the Commission already decided that DCN is the appropriate parameter in AIC's last rate case because that is the tariffed withdrawal rights.

Staff notes that in its last two rate cases, AIC has sought to charge daily-balanced transportation customers for more than their tariffed peak day withdrawal rights on a CD. Staff suggests if AIC 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, Staff indicates AIC proposes to allocate costs based on MDCQ but to allocate CD withdrawal rights based on DCN, noting that AIC has provided no more convincing argument in this case than it did in the last and the Commission should reject their proposal again.

Staff states that AIC has provided the data from its historical peak days for the past 5 years, which 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 any attempt to allocate costs to them based on MDCQs will over allocate storage costs to them.

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, 43% of their MDCQ. Staff states daily-balanced transportation customers historically had access to only 9% of MDCQ, and 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.

Additionally, Staff asserts that AIC's equitable method using the MDCQ should be rejected because it is internally inconsistent. Staff notes that AIC has claimed that it plans for a peak day using the 20% of MDCQ number for daily-balanced customers. Thus, AIC plans for bank withdrawals at 20% of MDCQ, would charge those customers based on 20% of MDCQ, but only gives tariff rights at 20% of DCN, a number that Staff has shown is historically only 9% of MDCQ.

Staff notes it does support AIC'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.

Staff states that AIC plans for Rider TBS to go into effect on May 1, 2012, however 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.). Staff avers that Mr. Eggers addresses interim rates in surrebuttal testimony and claims that AIC applied the "equitable method" for that period using MDCQs instead of DCNs (and presumably a full 10 days of bank).

Staff alleges that 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. Staff states this ensures that there is no three month gap in which costs spike before more reasonable rates discussed here are implemented. Staff indicates the charges should reflect the storage costs determined in this case, but the method should remain fixed until Rider TBS becomes effective.

While AIC maintains that it is not operationally comparable to Nicor and that Staff did not show that the two are operationally comparable, relying on the Antioch Milling Co. case to argue it is Staff's burden to show operational comparability, Staff opines that the reliance on this decision ignores the fact that the Commission required AIC and Staff to participate in a workshop process which was to, at a minimum, result in tariffs implementing for AIC the banking provisions currently employed by Nicor, Peoples, or North Shore. Staff argues the Commission has already determined that the operations are comparable, and while the Commission made it clear AIC could raise its concerns about adopting the banking provisions and could propose alternatives, Staff asserts AIC bears the burden of demonstrating what changes to those methods are operationally necessary. To the extent AIC raised concerns about specific operational differences between AIC and Nicor, Staff argues it has demonstrated that they do not affect AIC's ability to implement Staff's proposed changes. Staff notes that AIC proposed uniform transportation tariff provisions in its last two rate cases. While AIC asserts there are operational differences between its fields, Staff opines AIC apparently finds these differences insignificant when it wants to work with them.

Although AIC also asserts that Staff is proposing numerous Nicor transportation tariff provisions to be imposed on AIC, Staff claims only two changes are proposed, the linked maximum storage capacity and CD withdrawal method, each adjusted to reflect the physical attributes of AIC's system.

While AIC argues in its Initial Brief that its proposed Rider TBS banking provisions account for its own operational circumstances, Staff believes AIC cannot take credit for Rider TBS's proposed maximum storage capacity and peak day deliverability because it is levels for both that the Commission ordered it to provide under Rider T in AIC's 2007 rate case. Staff notes that AIC customers responded to those provisions and elected to take transportation service, with AIC responding to this migration as needed and experiencing no operational difficulties. Staff asserts that just because the system works with the current levels does not mean that it cannot be expanded and the process repeated.

Staff notes that AIC also objects to having to buy more off-system assets to allow transportation customers proportional storage rights, claiming that this results in significant cost to sales customers. In Staff's view, the proportional storage rights are appropriate and transportation and sales customers should share the cost. Staff urges the Commission to require AIC to provide transportation customers a proportional amount of the on-system capacity, claiming that sales customers would still pay for and receive a proportional amount (68%) of the on-system deliverability and 100% of the off-system deliverability. While AIC argues that Staff's proposal will increase costs to sales customers, Staff indicates that such a result is not certain. If transportation customers take less capacity than they have currently, Staff believes AIC may actually be able to reduce their off-system assets under Staff's proposal because, unlike AIC's proposal, a decision to reduce banks will result in lower peak day rights.

Further, AIC has made the case that its expectation is that transportation customers as a group will decrease their bank usage relative to current 10-day banks. AIC provided two reasons for this expectation. First, transportation customers' current maximum inventory is significantly less than the full 10 days. Second, AIC witness Eggers estimated a negative price hedge value for storage. Staff has provided two additional reasons to expect a reduction in transportation customers subscribed bank size. First, since costs under both Staff and AIC's proposals would be tied directly to the amount of storage, transportation customers are unlikely to keep capacity that they do not use. Second, Staff's fall injection target would require customers to fill their subscribed storage. Taken together, it is unlikely that transportation customers would subscribe to as much bank as they currently have.

Finally, capacity needed for monthly balanced customers would also be lower under Staff's proposal than AIC's, since peak day withdrawal rights for monthly-balanced customers would be lower. Thus, it is likely that Staff's proposal will reduce peak day needs for the system.

While AIC claims in its Initial Brief that the uncertainty of cost impacts is a reason to reject Staff's proposal, Staff avers that AIC is currently over-planning for the peak day because it has secured sufficient deliverability to cover transportation customers' bank withdrawals at a level in excess of the level allowed by the tariff. As Staff noted in its Initial Brief, over-planning for the peak day raises costs for sales customers. Staff opines that AIC has not demonstrated that Staff's recommended change to CD withdrawal rights will affect AIC's operational integrity.

While AIC asserts in its Initial Brief that giving transportation customers a large percentage of on-system assets would be destabilizing to its system, Staff suggests this is incorrect. Staff states that AIC incorrectly states that under Staff's proposal a transportation customer could take 32% of its bank, however this is not correct. Staff indicates that under its proposal, a transportation customer can take 2.2% of its bank, which is 32% of its MDCQ, therefore the amount calculated by AIC is greatly overstated.

Staff also disagrees with AIC's claim that other utilities require fall and spring cycling targets, noting that Nicor, Peoples, and North Shore all have a single fall injection target. Staff suggests the Commission specifically rejected a spring target in Peoples and North Shores 2007 rate case, Docket Nos. 07-0241 and 07-0242 (Cons.).

Staff notes that AIC proposes to recover the costs associated with unsubscribed bank capacity from sales customers through a charge called the UBCC in Rider S, as AIC 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. AIC contends these costs should be borne by sales customers because they are "the beneficiaries of the unsubscribed bank capacity."

Staff agrees that a cost mechanism is necessary to support this level of bank flexibility for transportation customers, and notes that the Commission has approved a similar mechanism in Nicor's Rider 5 – Storage Service Cost Recovery ("SSCR"). Staff therefore recommends that the Commission approve the UBCC. If AIC's proposed addition of the UBCC to Rider S is allowed by the Commission, Staff witness Jones recommends that a formula to calculate the UBCC and language providing for an annual reconciliation be included in Rider S, as shown in Staff Ex. 6.0 at 12-14. Staff also notes that AIC agrees with this language.

c. IIEC Position

IIEC states that AIC proposes to allocate storage capacity to the "Large Volume Transportation Customers" using what is commonly known as the Nicor method. IIEC indicates that in rebuttal AIC acknowledged that the Nicor method properly applied, resulted in the allocation of 15 days of MDCQ to each transportation customer. IIEC notes this means that transportation customers would be allocated 15 days times their MDCQ of storage capacity under the Nicor method. IIEC accepts the recalculation and recommends that each Transportation customer be permitted to subscribe up to a maximum of 15 days of storage consistent with the Nicor method. IIEC recommended that this limit apply to both individual and aggregate allocations of storage to transportation. In its surrebuttal testimony, IIEC notes AIC accepted the maximum of fifteen times MDCQ for individual transportation customers' and agreed that any unsubscribed storage capacity would be available for customers desiring more than 15 days of capacity.

However, IIEC indicates AIC still proposes an aggregate limit (the BSL) on transportation storage capacity equal to ten days or 5.482 Bcf, which IIEC notes is substantially less than the proportional share of AIC's on-systems storage that would be allocated to transportation customers as a whole under the Nicor method. IIEC notes that AIC's concerns on the aggregate storage limit were not eliminated with the corrected 15-day individual limit. IIEC indicates that under the Nicor method, transportation customers should be allocated 8.22 Bcf of AIC's on-system storage, which AIC to limits 5.48 Bcf, based on its 10 day aggregate limit.

IIEC notes that despite AIC's proposal to strictly impose the 10-day aggregate limit, AIC indicates that transportation customers are not currently using their existing 10-day bank allowance and are unlikely to subscribe to the aggregate 10-day limit under the proposed program. IIEC indicates AIC has not demonstrated or claimed any inability to meet the 15-day limit. IIEC suggests that AIC's approach is inconsistent with the Nicor method and has the potential to prevent transportation customers from subscribing to the maximum of 15 days of storage AIC proposes to establish as the individual customer storage limit and has not been shown to be a necessary limitation.

Therefore, while IIEC agrees with the AIC maximum individual customer storage limit of 15 days times MDCQ, and the opportunity for customers to subscribe to more than 15 days of storage if storage capacity is available, it disagrees with the 10-day aggregate storage limit and recommends the Commission reject the same.

IIEC indicates that AIC proposes the use of the so-called Equitable Method to allocate storage costs for Rider TBS between sales and transportation customers. Under that method, 50% of the storage costs are allocated between sales and transportation customers on the basis of deliverability and 50% on the basis of capacity. IIEC states there are several reasons for the Commission to reject the use of the

Equitable Method for the allocation of costs between sales and transportation customers in this case.

IIEC indicates that the Equitable Method is a method that is primarily used by the FERC to allocate costs between pipeline contract storage service customers and transportation customers, and is not used for the allocation of storage costs between two groups of customers such as sales and transportation customers. IIEC alleges it is used for allocation of storage to customer groups with a limited service relationship to the regulated provider. Unlike pipeline contract storage customers, IIEC notes that AIC's sales and transportation customers have a current and historic end-use customer relationship to AIC in this case, purchasing multiple services from AIC, and have contributed to the rate base for AIC's gas operations, including its storage assets.

IIEC notes the service purchased by contract storage customers from the pipeline is, in fact, a full storage service providing the customer with all the benefits of storage, such as peak day deliverability, hedging capability, and balancing capability. In this case IIEC alleges AIC is offering transportation customers an unbundled balancing service which does not provide AIC's transportation customers with all of the benefits of storage.

IIEC states the Equitable Method also fails to reflect the way in which storage capacity itself is allocated to transportation customers by AIC, noting that AIC allocates storage capacity on the basis of the customer's MDCQ and the associated costs should be allocated accordingly. IIEC indicates that otherwise, the cost allocation will not reflect cost causation. IIEC alleges that use of the Equitable Method results in a departure from cost-based rates because it allocates a portion of costs on assumed levels of peak day deliverability rather than on the MDCQ factor used to allocate the capacity. IIEC indicates the Commission has approved the use of the MDCQ as a means of subscription to storage or allocation of storage for other Illinois utilities, including for Nicor in Docket No. 08-0363.

IIEC argues that for these reasons, the Equitable Method should be rejected for use in allocating storage costs to Sales and Transportation customers in this case. In addition, IIEC urges the Commission to not use the AIC version of the Equitable Method in any case because it overstates both the "maximum" and the "probable" deliverability used by Transportation customers on a peak day, noting that the AIC calculation of the deliverability allocation uses 50% of all monthly balanced customers' MDCQ and 20% of all daily balanced customers' MDCQ.

IIEC asserts that the AIC version of the Equitable Method incorrectly calculates the "maximum" because daily balancing Transportation customers cannot withdraw 20% of their MDCQ and monthly balanced Transportation customers cannot withdraw 50% of their MDCQ on a peak day, as assumed by AIC. Furthermore, once a daily balanced customer has used the amount of gas specified in its daily nomination, IIEC indicates the next 20% of its usage will be considered a withdrawal from storage. IIEC states additional usage beyond the 20% is cashed out according to AIC's cash-out schedule. IIEC opines that a customer's maximum possible storage deliverability is 20% of the customer's peak day DCN (which cannot exceed, and is typically much less than, the customer's MDCQ), noting the same problem arises for monthly balanced customers.

IIEC alleges that AIC has overstated the probable deliverability from storage used by Transportation customers, noting that there are important differences in FERC's application of the Equitable Method and the AIC application. Under the FERC application, IIEC states the contract user acquires all the benefits of storage through its purchase of storage capacity from the pipeline. Therefore, IIEC indicates it is probable that such a customer's maximum use on a peak day will be the maximum use allowed under the contract.

However, IIEC states a transportation customer on the AIC system is purchasing a balancing service. IIEC argues the customer's peak day storage deliverability will be a function of the customer's imbalance on that day, and it is not a function of the customer's desire to use storage gas, in lieu of flowing gas supplies, to avoid high cost gas purchases. Under such circumstances, IIEC asserts the appropriate measure of deliverability is not simply the sum of every customer's maximum peak day withdrawals, but rather the probable maximum withdrawals on peak days.

In making such a calculation of probable deliverability, IIEC claims one must consider transportation customer diversity, in that consideration should be given to the fact that some customers may over-deliver gas and thus may actually be injecting gas into storage, while other customers may under-deliver gas and thus be making withdrawals from storage. Since under-deliveries may be offset by over-deliveries, IIEC notes the calculation of probable peak day deliverability is an empirical question, not just a matter of calculating the maximum possible withdrawals that could possibly occur, however AIC has not made such an empirical calculation in this case.

Because AIC has overstated both the probable and maximum deliverability used by Transportation customers, IIEC states the results of its calculations do not support use of the Equitable Method. IIEC recommends the Commission reject the use of the Equitable Method and instead allocate storage costs to Transportation customers on the basis of capacity. IIEC has calculated the appropriate storage costs and unbundled bank charges using a capacity allocation of storage costs. Specifically, IIEC divided the total annual on-systems storage costs of 32.5 million by the total on-systems storage capacity of 25.8 million Dth, deriving an annual cost per Dth of storage capacity of about $1.26. IIEC states this translates to 10.5¢ per therm of subscribed storage capacity on a monthly basis or 1.05¢ per therm of unsubscribed storage capacity. IIEC notes that Staff witness Sackett came up with almost exactly the same cost per Dth of storage capacity using essentially the same method. Therefore, the Commission should adopt IIEC's recommended allocation of storage costs between Sales and Transportation customers and the associated charges.

d. Commission Conclusion

The Commission notes that in AIC's last rate case, the Commission required AIC to submit a tariff implementing the Nicor method for determining bank size, however, the Commission further allowed AIC to offer an alternative, preserving the flexibility to determine the most appropriate banking provisions under Rider T for AIC. In accordance with the Order, the Commission recognizes that AIC held workshops to gather input for its proposed tariff. Reflecting concerns AIC addressed in the workshops, and as authorized by the Commission in Docket Nos. 09-0306 et al. (Cons.), AIC submitted alternative tariffs setting forth unbundled, subscribable banking service, identified as Rider TBS. AIC's proposal also provides for the allocation of on-system storage costs to Rider T customers, unsubscribed bank cost recovery language in Rider S, an election process that allows Rider T customers to subscribe to their preferred bank size up to a 15 day times MDCQ limit, and other implementation and service management provisions.

The Commission notes that Staff has proposed various other modifications to AIC's proposed Rider TBS by replacing certain portions of the tariff with Nicor banking provisions. It appears to the Commission that Staff proposes to modify various portions of the tariff including the MDCQ, system peak day deliverability, to adopt the Nicor BSL, and a single fall injection target. The Commission notes that AIC argues against many of Staff's recommended changes by asserting that there are significant operational differences between AIC's gas distribution system and that of Nicor.

During the course of this proceeding, it appears to the Commission that Staff has proposed certain changes or additions to Rider TBS, based on Staff's belief, as expressed in Staff's Reply Brief, that the Commission had settled the question of whether there were operational differences between AIC and Nicor. While Staff asserts that the Commission had determined there were no operational differences between AIC and Nicor, the Commission disagrees with that assessment. The Commission notes that in Docket Nos. 09-0306 et al. (Cons.), under the section of the Order regarding this issue the Commission found as follows:

> As for the subject of the workshops, which should be open to all those interested, the Commission notes less agreement by the parties. While Staff proposes that specific methods employed by other Illinois gas utilities be considered and modified for use by AIU, AIU urges the Commission to refrain from limiting discussion in any way. The Commission finds merit in Staff's proposal since it concerns methods which it is familiar with and would promote consistency among the gas utilities operating in Illinois. Customers with facilities served by differing gas utilities are apt to find such consistency attractive. AIU's view, however, deserves consideration as well. <u>By directing that the workshop participants develop tariffs implementing the same banking provisions of Nicor, Peoples, and North Shore, the Commission fears that it would be</u>

> making a decision before having all of the facts. Order at 283, emphasis added.

As it appears the Commission had not determined that there were no operational differences between AIC and Nicor, the Commission finds the burden would be on Staff to support the changes it has proposed to Rider TBS. The Commission finds that Staff has not met that burden, and believes the evidence is clear that there are significant operational differences between AIC and Nicor's gas distribution systems.

The Commission also notes that it appears that AIC is proposing to recover 50% of its storage costs through a Deliverability Charge, and the other 50% through a Capacity Charge, applying what it calls the "Equitable Method." Staff suggests that this method would allocate a significant portion of costs to the first day of bank, which would result in negative impacts to customers. Staff argues in favor of the Nicor method for allocation of storage costs. IIEC also argues against AIC's use of the Equitable Method, and suggests instead calculating the appropriate storage costs and unbundled bank charges using a capacity allocation of storage costs. The Commission is concerned with the suggestion that AIC's method may result in negative impacts, such as to cause some customers to select no bank so as to avoid high initial bank charges. Based on the evidence presented, the Commission is of the opinion that the method endorsed by IIEC is more appropriate for determining storage costs.

The Commission recognizes that the dispute between Staff, AIC, and IIEC over transportation banking provisions is rooted in complex issues of gas storage operation, transportation customer behavior, and accounting. As a result, the Commission believes that it must exercise caution in picking and choosing among the various aspects of the parties' proposals. The Commission is particularly concerned that certain aspects of Staff's proposals would increase the rights of transport customers at the expense of sales customers, which the Commission feels it cannot support based on the record in this proceeding. The Commission also finds that Staff has failed to demonstrate that there is sufficient operational comparability between AIC and Nicor that would provide a basis for applying many aspects of Nicor's tariffs to AIC. The Commission therefore finds the proposed Rider TBS and changes to Rider T tariffs proposed by AIC, except with regard to the Equitable Method discussed above, are the more reasonable and should be approved.

2. Rider T – Cashout Provisions

a. AIC Position

AIC indicates it has proposed to modify the current cashout provisions in Rider T-Transportation Service in order to provide better protections to its sales customers and incentivize transportation customers to better manage their accounts. AIC indicates that cashout provisions are tariff provisions that require transport customers to settle imbalances by purchasing or selling gas from sales customers. AIC states the proposed cashout provisions are enhanced to provide recovery of costs related to managing imbalances caused by transportation customers for over or under delivering. Currently, AIC notes that cashouts are charged at a market price, and the cashout volume is either purchased from (for under deliveries), or sold to, sales customers (for overages). Under AIC's proposal, the transportation customer will be charged the market or PGA cost, whichever is higher, to buy gas from sales customers in the case of under deliveries, and in turn, the transportation customer can sell excess deliveries at the lower of the market price or PGA. AIC asserts that this price proposal represents a common sense measure to ensure that transportation customers pay the highest price amounts when they under-deliver gas and AIC pays the lowest price when transport customers over-deliver.

AIC notes that the Commission has recently recognized the concern with adverse impacts on sales customer of cashout provisions that may allow arbitrage opportunities by transport customers. In Mid-American Energy Co.'s latest rate case, AIC states the Commission found that "sales customers have, at times, shouldered financial responsibility for the consequences of that arbitrage." Docket No. 09-0312, Order (Mar. 24, 2010) at 40-41. AIC indicates the Commission went on to approve a cashout pricing proposal that charges transportation customers the highest daily price among the three indices to cover their delivery shortfalls, and that uses the lowest daily price among the indices to buy excess delivered gas, finding that the utility's proposed high/low cash-out solution was properly aimed at curtailing arbitrage, and any associated subsidy.

AIC states it has proposed a similar "high/low" solution here, noting the Commission has approved similar cashout language to AIC's proposal in the tariff of legacy utility AmerenCILCO and in Nicor's tariff. AIC argues the evidence provided in this proceeding shows that AIC's current cashout mechanism is failing to perform its intended purpose to "protect sales customers," as Staff averred they should when Rider T was authorized in Docket Nos. 07-0585 et al. (Cons.).

AIC indicates that the total cost for the services required to cover daily balanced customer imbalances is $2.3 million annually, noting that imbalances are managed in real time, using adjustments to on-system storage, leased storage, pipeline deliveries and linepack. When imbalances occur, AIC states its system is impacted through adjusted injections or withdrawals from on-system storage and leased storage, changes in linepack, and gas loaned to or borrowed from pipelines. AIC notes sales customers incur a cost from all of these, except linepack. AIC avers that charges under the balancing agreements with the pipelines are paid only by sales, not transportation customers, and any extra withdrawals or injections incur fuel charges from the pipelines that are paid for by the sales customers. AIC opines that any no-notice storage fees are also paid for by the sales customer. AIC argues where such costs are incurred by sales customers, appropriate penalties should be adopted, citing Abbott Laboratories, Inc. v. Illinois Commerce Commission, 289 Ill. App. 3d 705, 712 (1st Dist. 1997). Furthermore, AIC alleges managing transportation customer imbalances with adjustments to on-system storage injection and withdrawal plans affect the ability to store or withdraw the desired amount of supply for sales customers.

AIC argues that Staff incorrectly assumes that the penalty revenues from transportation customer cashouts adequately cover these costs. AIC notes however, the $2.3 million in costs are far in excess of the $583,000 average in premiums paid by transportation customers, through the cashout mechanism, and AIC's cashout proposal is designed to bring cashout premiums more in line with balancing costs.

Currently, AIC notes its transportation customers pay for banking rights, but pay nothing for on-system and off-system storage used to manage cashout imbalances. AIC indicates that these imbalances rely upon system supply resources which are paid for by the sales customers. AIC states its banking service allows transportation customers to access up to 20% of their nominations from their bank to cover any differences between their deliveries and usage at no cost premium. Under AIC's current tariff, after a transportation customer utilizes its bank, it can then cashout up to an additional 20% of its nomination without penalty. AIC asserts this additional 20% cashout acts like overdraft protection for transportation customers, in that if the banking service does not provide enough gas to cover an under-delivery, they can access a savings account (sales customers) to cover the spread and are not charged a fee up to 20% of their nomination. AIC argues its proposal mitigates these impacts on sales customers, while cashout revenues would continue to be credited to the sales customers through the PGA mechanism to offset the costs incurred to maintain cashout imbalances.

AIC notes a negative cost consequence to sales customers can occur under the current cashout provisions when, for example, a transport customer under delivers. AIC states the shortfall is made up with sales customer gas (ie, PGA gas), and AIC pays the transport customer a market price which is lower than the PGA price. AIC provided evidence of such negative cost consequences to sales customers from 2009 and 2010 where the cashout revenue was insufficient to avoid a negative cost consequence. Therefore, AIC argues its proposed pricing mechanism, by using of the PGA prices as a baseline, is more reasonable than market price, which is the current baseline.

AIC indicates Staff's opposition to AIC's cashout mechanism is based on at least two flawed assumptions. First, Staff incorrectly assumes AIC can simply buy market priced gas to make up cashout imbalances, as AIC notes every purchase flows through the PGA with all supplies AIC provides to its distribution system priced at the PGA price. When buying gas from transportation customers, AIC urges that sales customers should never have to buy it at a price greater than their supply, the PGA, as a result of transportation customer activity.

AIC states that Staff believes net purchases are realized during the gas day by a drop in system pressure and AIC responding by buying more gas - at the market price, not the PGA. AIC indicates however that it does not respond to a drop in pressure by buying gas, noting that flexible storage resources are most often used. AIC indicates it can only purchase and nominate gas for the first 8 hours of a gas day due to North American Energy Standards Board rules for nominations on the interstate pipeline system, leaving insufficient time to respond to pressure drops with gas purchases. Even if AIC could purchase gas beyond the first eight hours of a day, AIC notes it would still be purchased through the PGA, therefore Staff's concerns are unfounded and should be rejected.

AIC asserts that its proposed cashout mechanism provides an incentive for transportation customers to better align nominations to load. AIC notes that IIEC witness Gorman accurately concludes that PGA prices still routinely exceed market clearing prices, at levels as high as 206% of the market price. As transportation customers have a 20% free margin of error on their nominations, AIC contends that such wide latitude does not provide any incentive for a transportation customer to better maintain their accounts if they can continue to buy and sell at market price and take advantage of any price differences. AIC argues its cashout proposals will provide the incentive to transportation customers to minimize or eliminate their cashout imbalances.

AIC also notes that its current cashout provisions do not deter transportation customer behavior that might impair the system. AIC indicates the 20% of the DCN permitted to be cashed out at the Chicago market price can often be less than the transportation customer is paying for their gas supply, so a transportation customer would be incented to under-deliver and purchase from AIC's sales customers at the market price. AIC states the 10% penalty imposed on imbalances greater than 20% DCN after banking offers little deterrent for transportation customers to minimize imbalances. AIC asserts that evidence showing that the current cashouts are not minimizing imbalances is evident since transport customers consistently under-deliver, noting there is a net of approximately 20,000 therms of average daily under-delivery on the total system. AIC contends this imposes costs on sales customers every day, while AIC's proposed cashout provisions will provide incentives to reduce these imbalances.

AIC indicates that Staff concedes therefore that there is an under delivery issue that should be addressed, with Staff now suggesting there may be reasonable alternatives to AIC's proposal, such as to add a basis to the cashout price. AIC notes, however, that Staff has not provided any explanation or detail supporting their proposal. While AIC is not opposed to discussing alternatives to its cashout mechanism with the goal of minimizing balances on the record evidence in this case, AIC asserts its proposal is the most reasonable and therefore should be adopted.

AIC asserts that Staff's Initial Brief contains two significant incorrect assertions: that AIC has provided no evidence regarding negative cost consequences to PGA customers is false; and that AIC has provided no evidence that the current cashout provisions are inadequate. AIC submits it has provided substantial evidence that current cashout provisions are not adequate, including: (1) data showing negative costs consequences to sales customers, (2) balancing costs of $2.3 million far exceeding cashout premiums of $583,000, and (3) a pattern of under-delivery by transportation customers.

AIC argues in its Reply Brief that the evidence shows that there were negative cost consequences to sales customers from 2009 and 2010 where the cashout revenue was insufficient to avoid a negative cost consequence. AIC asserts that there was a $2.3 million annual cost for the services required to cover daily balanced customer imbalances, which exceeds the $583,000 average in premiums paid by transportation customers through the cashout mechanism. AIC suggests this means the costs to cover these imbalances is almost four times what transportation customers pay, and notes that Staff acknowledges that there is a problem with under-delivery.

AIC opines that Staff's Initial Brief shows a continued misunderstanding of the source and price of gas supplies used to balance the system. AIC states that making up for cashout imbalances is not a simple as AIC buying more market priced gas, noting that imbalances are corrected using distribution system supplies, i.e., sales customer gas – which are priced at the PGA price. AIC asserts that when buying gas from transportation customers, the sales customers should never have to buy it at a price greater than their supply, the PGA, because that exposes them to higher prices than they would have otherwise experienced as a result of transportation customer activity.

Although Staff claims in its Initial Brief that imbalances can be offset by market purchases for which the daily market price compensates the PGA for the gas purchased, AIC avers that it does not respond to imbalances by buying gas – flexible storage resources are most often used. Because imbalances are corrected using distribution system supplies which are priced at the PGA, AIC suggests it is logical that the transportation customer's cashout mechanism use PGA prices as a baseline. IIEC does not agree that cashout volumes are necessarily purchased from or sold to PGA customers, but argues that AIC cures imbalances at the marginal or market price. While IIEC also argues that using PGA prices rather than market clearing prices produces a margin, which benefits the sales customers, AIC contends that any margin serves to offset the costs incurred by the sales customers when transportation customers cannot adequately match nominations to usage. AIC states it has shown that cashout premiums are inadequate to recover the full amount of balancing costs imposed on AIC's sales customers and these imbalances are corrected through the PGA. AIC argues that its cashout proposals will provide the incentive to transportation customers to minimize or eliminate their cashout imbalances.

b. Staff Position

Staff notes that AIC proposes to change its Rider T cashouts so that AIC 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. Staff indicates that AIC has also proposed an identical cashout in the new Rider TBS. Staff states that AIC made this same proposal in its 2007 rate case, which Staff opposed in that docket.

Staff argues that AIC has provided no evidence regarding the negative cost consequences to PGA customers under the current system, and Staff indicates the cashout provisions are already designed to deter transportation customer behavior that might impair the system. Staff argues there is no evidence that the current provisions are inadequate, although AIC argues that the PGA is more appropriate because it is the price paid by sales customers in that month for gas.

Staff witness Sackett explains how diversity keeps the impact of transportation customers as a group minimal, and in fact, claims transportation customer imbalances may benefit sales customers. Staff asserts that due to diversity, AIC does not balance each customer individually each day, but rather balances the entire system. Staff avers the imbalance of transportation customers may be off set by unplanned for imbalances of sales customers. Where transportation customers contribute to net imbalances, Staff indicates that imbalances can be offset by market purchases for which the daily market price compensates the PGA for the gas purchased. The daily market price, Staff opines, not the PGA is the appropriate price to use for transportation customer imbalances. Even if AIC were not able to make its purchases by the end of the day, Staff argues AIC 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 notes AIC 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 asserts that the evidence shows 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. Staff states there is no evidence that the 33,289 therms daily average harms the system. Staff avers that this tendency to under deliver will totally disappear if a CD is declared due to a $6 per therm penalty. Staff notes that AIC acknowledges that these under-deliveries do not destabilize the system.

While AIC argues that these imbalances may be inconsequential when compared to a peak day volume but nevertheless harm the sales customers economically, Staff opines that the evidence provided does not demonstrate that this is the case. Although AIC claims that the cost for all gas on AIC's system is the PGA price and there is no separate market priced gas waiting to handle cashout imbalances, Staff notes AIC admits there have been no actual purchases of any gas at the PGA rate.

In addition, despite assurances that AIC cannot buy gas at the daily price, Staff states AIC witness Eggers acknowledged under cross-examination that AIC makes daily gas purchases at its city gate at the CCP, the exact same cashout price charged to daily-balanced customers. Thus, Staff claims the use of the PGA is not appropriate, and the current tariffed price is reasonable.

Staff asserts there are other market-based ways to address under-delivery rather than abandoning the market in favor of penal PGA cashouts. Staff indicates a reasonable alternative that would correct the under-deliveries would be to add a basis to the cashout price. Staff argues that more reasonable measures such as this should be considered first, however if the Commission is inclined to seek a corrective path to this under-delivery issue, it should encourage AIC to work with Staff to find a less draconian means of addressing the issue through an appropriate tariff modification.

Staff notes that AIC has offered two data sets to support its cashout proposal, the first being data from a two week period in the winter of 2009-2010 which AIC alleges shows evidence of negative cost consequences to sales customers because the cashout revenue was insufficient. Staff argues however, this data “from 2009-2010” is not two years of data but rather two weeks of data, and is an anomaly because the CCP price is equal to or greater than the PGA during this period. Staff asserts that IIEC Ex. 8.1 demonstrates that on average, AIC’s PGA is 147% of the market price, and that this two week period was from the only month where the PGA was less than the average CCP. Staff opines that AIC chose the only period where such a price relationship occurred in any Rate Zone for 2010 to support its position.

Staff avers that even AIC’s alleged cost consequence to sales customers from that period is actually a benefit when netted against the cashouts premiums transportation customers paid. Staff asserts there are in fact no net negative cost consequences from this time period and AIC has provided no other evidence of any alleged cost consequences.

Staff claims the second data set that AIC provides is Ameren Ex. 34.5, which shows under-deliveries, which calculates under-delivery for the system in the period since the current cashout provisions went into effect. Staff claims it calculates the system net under-deliveries equal to an average of 33,289 therms daily, which is less than 0.2% of AIC's peak design day. Staff opines the average annual amount of the under-delivery is also less than 2% of transportation throughput, less than 1.5% of sales throughput and less than 1% of AIC’s total throughput. Staff avers this magnitude of under-delivery is insignificant and insufficient to justify AIC’s proposed change in the cashout provisions.

Staff notes that AIC in its Initial Brief wrongly projects an assumption on Staff’s part that AIC can simply purchase market priced gas to make up cashout imbalances, stating that Staff’s assumption is incorrect. Staff opines that AIC implies that the PGA is the cost of incremental gas purchases, however Staff indicates it has established that the market price is unlikely to exceed the PGA. Staff avers that AIC’s conclusion that the PGA value serves as a good estimate of incremental cost is unfounded.

Staff asserts that in its Initial Brief, AIC justifies its cashout proposal by pointing to a Commission decision in Mid-American Energy Co.’s most recent rate case, Docket No. 09-0312. Staff notes that AIC maintains that its proposal provides an incentive for transportation customers to better align nominations with load, and claiming that the

Commission's decision in Docket No. 09-0312 recognizes that high/low cashout proposals create an incentive for transportation customers to accurately balance their daily supply and demand. Staff argues this quote does not fully summarize the approved tariff in Docket No. 09-0312, and a fair reading of the Order in Docket No. 09-0312 and the MidAmerican tariff argue for the adoption of Staff's position on this issue.

While AIC also claims that the Commission has approved similar cashout language to AIC's proposal in the tariffs of AmerenCILCO and Nicor, Staff asserts that the referenced Commission approval is overstated and irrelevant to AIC's daily proposal.

c. IIEC Position

IIEC notes that AIC has proposed that the pricing mechanism in the cashout provisions contained in Rider T be modified, by proposing that a transportation customer must buy gas from AIC at the higher of the market price or PGA cost when it under-delivers gas to the system and sell gas to AIC at the lower of the market price or PGA cost when it over-delivers gas to the system. IIEC indicates that AIC argues this approach protects sales customers from any negative cost consequences of the cashouts.

IIEC does not agree that cashout volumes are necessarily purchased from or sold to PGA customers, and notes that an appropriate analysis assumes that AIC's portfolio for sales customers is the proper size for those customers and that marginal unplanned purchases or sales to cure customer imbalances are made by AIC at the marginal or market price. IIEC notes that under AIC's proposal, cashout purchases from transportation customers would be made at the lower of either 90% of the market price or the PGA price and cashout sales to transportation customers would be made at the higher of 110% of the market price or the PGA price. IIEC indicates there is a margin produced from these cashout transactions and sales customers will receive the benefit of that margin.

IIEC suggests that introducing the PGA as a cashout transaction price, exposes transportation customers to significant out-of-market costs for these cashout transactions because PGA prices have been well above market. Comparison of market prices and the AIC PGA prices for the year 2010 show that on an annual average basis, transportation customers with negative imbalances in the AmerenCILCO zone (Rate Zone 1) would be forced to pay 142% of the market price for gas, customers in the AmerenCIPS zone (Rate Zone 2) 157% of the market price for gas, and customers in the AmerenIP zone (Rate Zone 3) would pay 143% of the market price for gas, under the AIC modified cashout proposal. In fact, in November of 2010, AmerenCIPS transportation customers would have been forced to pay more than 206% of the market price for gas.

IIEC claims that AIC did not present testimony in its direct case which demonstrated that sales customers had been economically harmed under the existing cashout protocol. IIEC notes that in rebuttal AIC did present a comparison of the PGA to revenues from imbalance charges for a period of only 14 days from Rate Zone 2, claiming that this data showed that negative consequences occur under the current cashout protocol. IIEC states the limited data provided shows that on nine of 14 days the PGA cost was greater than imbalance revenues by a small amount, and suggest that even if AIC is correct in its characterization of this data, the shortfall between PGA revenues and cashout revenues can be corrected without modifying the cashout protocol as proposed by AIC. IIEC opines this can be accomplished, by reducing the PGA through lower cost purchases. IIEC avers the current calculation of imbalance charges provides an incentive for AIC to reduce its purchased gas costs to the benefit of sales customers, without imposing additional harmful penalties on transportation customers, therefore the present cashout benefits both sales and transportation customers.

IIEC argues that the purchase or sale of customer-owned gas should be looked at as marginal purchases that add or reduce costs at a unit rate of the market price for the given day. IIEC asserts that AIC's analysis does not necessarily demonstrate the existence of negative consequences from the current cashout protocol, and even if such discrete consequences did exist on particular days, IIEC claims it is a far cry from showing that in the aggregate, sales customers experience negative consequences. IIEC avers that the AIC proposal would harm transportation customers in order to correct a problem that has not been shown to exist, therefore the AIC proposal should be rejected and the cashout mechanism should remain as currently outlined in Rider T.

d. Commission Conclusion

The Commission notes that AIC has proposed to modify its current cashout provisions in Rider T-Transportation Service to charge transportation customers the higher of market or PGA cost to buy gas to cover under-deliveries, and in turn, to charge the lower of the market price or PGA when selling gas from over-deliveries. AIC believes this change is warranted because current cashout provisions do not allow AIC to recover the costs of managing imbalances and do not adequately protect sales customers, while the modified cashout provisions provide better incentives for better account management. AIC claims that the evidence in this case shows that current cashout provisions are not adequate, and that there is a pattern of under-delivery by transportation customers. AIC also claims that its evidence shows that the cost for balancing transportation customer imbalances far exceeds the cashout premiums those customers pay.

The Commission notes that both Staff and IIEC oppose AIC's proposed change to its cashout provisions currently in place, suggesting that the imbalances are not as severe as AIC suggests, and that AIC's analysis does not demonstrate negative consequences form the current cashout proposal. Staff and IIEC also note that AIC's comparison of the PGA to revenues from imbalance charge was only for a period of 14 days in Rate Zone 2.

The Commission finds there has been insufficient evidence to demonstrate the negative consequences alleged by AIC due to the current cashout provisions. The Commission invites AIC to revisit this issue in future rate cases, however the Commission expects a more extensive analysis of the issue, and would appreciate comparisons from each of the three Rate Zones. The Commission finds that current cashout provisions of Rider T are sufficient at this time and AIC's proposed changes are rejected.

XI. PROPOSED SMALL VOLUME TRANSPORTATION PROGRAM

A. AIC Position

AIC states that RGS recommends that the Commission direct AIC to develop a natural gas choice program in AIC's service territory for residential and small commercial customers. AIC indicates it does not oppose a residential gas customer choice program subject to the following criteria: (1) there are identifiable customer benefits; (2) the cost of implementing such a program is reasonable; and (3) should the Commission approve such a program, AIC would be entitled to recover all prudently incurred costs in a timely manner.

In response, RGS recommends that within one month of the entry of the order in this docket, Staff and interested parties begin a six-month workshop process by which the parameters of a gas choice program would be developed as well as the related tariffs for Commission approval. AIC notes the results of the workshop would be presented in a separate proceeding and not necessarily in AIC’s next gas rate case.

AIC indicates it is not opposed to workshops per se, although AIC witness Seckler noted some concerns with such a process. However, as is noted by Staff witness Rearden, the ORMD is statutorily obliged to prepare a report that investigates the state of retail gas competition in Illinois, the barriers to development of retail competition, and other relevant information, under Section 19-130 of the Act. As part of this process requires gathering input from all interested parties for the report, Dr. Rearden testified the ORMD process presented a better opportunity for RGS to advance its recommendations, rather than in the instant rate case.

What AIC does not want is an obligation to conduct workshops, only to then have to repeat the process in the context of the ORMD process discussed above. AIC suggests it may be premature to assume that a workshop process could adequately address all the issues prescribed by law for review in the ORMD process. Further, at least in the judgment of AIC and Staff, as a practical matter, rate cases are not the best vehicles by which to design new and different services. Ms. Seckler testifies there is not sufficient information to design and implement a program based on the record evidence in this proceeding, nor as to what the cost of such a program would be.

In 2009, AIC indicates it prepared a high level analysis of the cost of modifying information technology ("IT") systems supporting the billing and customer information processes for a gas choice program. AIC estimated that the minimum cost to modify AIC's IT systems alone for a gas residential choice program would be $2.7 million; however, billing is only one aspect of a full program design and implementation effort. AIC states that cost data associated with customer communications, customer switching protocols, and RGS interface with AIC, are just a few of the program design features to be analyzed.

AIC alleges the issue is whether AIC should be required to complete a workshop process, when a similar process that would involve all Illinois stakeholders is still required under the specific requirements of the ORMD process statute. AIC suggests that Commission and stakeholder resources should to be taken into consideration in deciding if now is the right time, based on the record evidence, to proceed to a mass market gas choice program. Based on the record in this proceeding, AIC suggests that RGS' proposal is premature and redundant, and should be denied.

AIC notes it does not have a per se objection to workshops, however, AIC would oppose workshops unless a Gas Residential Choice Program was mandated by legislation or ordered by the Commission. Furthermore, AIC agrees with the position of Dr. Rearden, who pointed to the recent amendment to the Act whereby the ORMD is obliged to prepare a report that investigates the state of the retail gas competition in Illinois, identify barriers or obstacles to a retail gas choice program, and consider other relevant information and gather such information from stakeholders. AIC concurs with Dr. Rearden that awaiting the ORMD process is the better means by which RGS could advance its recommendations, rather than the current rate case.

AIC does disagree with RGS characterization that the parties agree that following a Commission order endorsing the expansion of customer choice to AIC's natural gas customers, the next step would be for the Commission to initiate workshops to develop the details for the program. In response, AIC notes both it and Staff have taken reserved positions and CUB has expressed doubt as to any customer benefits. While RGS asserts the ORMD report should not be a reason to delay workshops, AIC notes there is nothing in the legislation that speaks directly to the propriety of workshops under any circumstance, other than whatever might occur in the context of the ORMD process.

AIC indicates that it basically agrees with RGS' recommendations that, in the event workshops are required, the RGS proposal serves as a starting point for discussions. While the RGS proposal should be introduced in the course of workshops, AIC alleges it should not be given any more weight than any other proposal. AIC suggests the rate case is not the best means by which to adjudicate the design and implementation of a retail gas choice program, to which ICEA and Staff agree. AIC notes that no party, except perhaps RGS, has even attempted to try to define the parameters of such a program, which would include customer switching details billing mechanics, electronic data interface elements, IT transitions, customer education, community outreach, and the rate parameters for cost recovery.

If, however, AIC is required to implement a retail gas choice program, AIC asserts it should be able to recover all its prudently incurred costs. AIC states this would hold true even in the event the Commission would order workshops, and as a result of those workshops, order AIC to make a tariff filing providing for a retail gas choice service. As the design and implementation of a retail gas choice program could take affect when there is no rate case pending or no opportunity to recover the costs in a rate case, AIC urges the Commission to permit the utility to defer the costs as a regulatory asset and permit their recovery in the next gas rate case.

B. Staff Position

Staff notes that 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. Staff indicates 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 recommends that the Commission not order an SVT program for AIC in this rate case. Staff suggests that RGS failed to show that customers are better off with a SVT program, and did not offer details sufficient to enable such a program to be implemented. Staff argues 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. Staff also notes that under the recently amended Section 19-130 of the Act, the 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. Staff states that in compiling this report, the ORMD is directed to gather input from all interested parties, therefore the compilation of the ORMD report will provide an opportunity for 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, while the ORMD report will provide the Commission with an investigation of retail gas competition in Illinois. Staff suggests 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. Staff notes 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 notes that to date, the Commission has not mandated SVT tariffs for a utility that did not first file to implement one. Staff suggests the decision of whether AIC should have one should not be based upon whether the other large utilities in Illinois have one; rather the decision should be based on whether there are net benefits to customers from an SVT. Staff asserts that RGS has not provided empirical support for a finding that the program would benefit customers.

Staff states that RGS' assertion that there is no evidence concerning how the ORMD report will be compiled is equally applicable to the workshops RGS is advocating. Staff suggests the Commission wait for the report to the legislature mandated by the Act before ordering AIC to begin small volume transportation. While the process may be time consuming, Staff notes that workshops would also require time. Staff states the ORMD report is required to consider input from all interested parties, and should provide an opportunity for a broad range of entities to provide input. Staff asserts that AIC would ultimately have to file tariffs to implement an SVT program, which could result in a litigated docket that could take an additional eleven months. Staff urges the Commission to choose the method which would provide the most efficient and comprehensive basis for making a determination about SVT tariffs, which would be to wait until it can utilize the report from ORMD.

C. CUB Position

CUB notes that RGS initially proposed that the Commission and AIC make the development of a competitive natural gas mass market in the AIC service territory a significant priority. CUB initially objected to RGS' recommendation, citing its varied experiences with the small customer gas choice programs operated by Peoples and Nicor. CUB indicates that in rebuttal testimony, RGS witness Crist refined his proposal and recommended that the Commission order the parties to begin a six-month workshop process, which would begin no later than one month after the order in this docket, with recommendations to be made to the Commission about market design at the end of the six months. CUB notes that RGS suggested that the end result of the workshop process would be a tariff filing by AIC. CUB indicates it was able to present its response to this suggestion in its response to RGS-CUB 4.01, in which CUB stated that it would not oppose the development of a mass market gas choice program in the AIC service territory if the appropriate consumer protections, consumer education, and utility cost recovery provisions were in place.

CUB agrees with RGS that a properly designed choice program benefits all stakeholders; however CUB notes that what each party believes is a properly designed program may be different. CUB agrees that these issues could be further explored in a workshop process, should the Commission see fit to order one. As a result, if the Commission were to agree with RGS that a choice program should be made a priority in AIC's territory, CUB would agree that a workshop process would be beneficial to the parties to vet the many issues that require resolution before a choice program is instituted. If the Commission does direct the parties to commence workshops, CUB suggests that the participants first develop a comprehensive issues list which, at a minimum, should address necessary consumer protections and customer education programs in AIC's service territory, as well as utility cost recovery for implementation expenses. While CUB does not oppose the recommendation that the Commission initiate workshops for the purpose of exploring the implementation of mass market natural gas customer choice in AIC's service territory, CUB does not agree that the Commission should direct AIC to automatically file tariffs at the conclusion of the workshops.

D. RGS Position

RGS states it has presented substantial evidence concerning the elements comprising a well-functioning mass market retail natural gas competitive program and the process for formulating a detailed plan for final Commission approval. RGS witness Crist discussed the benefits of competition to all stakeholders, including consumers and AIC. Mr. Crist detailed four elements necessary for successful competitive markets: utility support; POR; fair allocation of commodity-related costs; and a properly-adjusted price-to-compare.

RGS suggests that the record evidence supports a Commission Order that paves the way for implementation of a mass market choice program and sets up a workshop process that fills in the details around the requirements for a successful competitive market and produces a tariff for Commission approval. RGS asserts the workshop process, which should last no more than six months, should begin using the detailed choice program outline documents provided by Mr. Crist with his testimony, should include all interested stakeholders, and should conclude with AIC's filing a tariff regarding the choice program with the Commission. RGS states parties will have ample time in that workshop context to work through operational issues, consumer protection and education issues, and cost allocation matters, as well as any other issues of concern to parties. RGS argues the goal of the workshop should be a mutually acceptable tariff that sets forth the details of the program, although should the workshop participants fail to reach full consensus on all tariff terms, parties will have a potential opportunity to further address them before the Commission during any review of the tariff after it is presented to the Commission. RGS argues this proposal represents a fair and appropriate plan that advances the Commission's policy favoring competition and the ability of AIC residential natural gas customers to gain the same ability to choose as other major energy utility customers in an efficient and timely manner on one hand, while protecting the rights of stakeholders to express views about any particular issues associated with the choice program as it is developed.

It appears to RGS that the parties agree that following a Commission Order endorsing the expansion of customer choice to AIC's natural gas customers, the appropriate next step would be for the Commission to initiate workshops to develop the details for the program. In light of the mass of evidence detailing the benefits of competition for AIC's residential natural gas customers and the fact that no party provided an alternative structure for a mass market natural gas choice program, RGS recommends that the Commission initiate a workshop process within a month of the Order to last no longer than six months. RGS suggests that the end product from the collaborative workshop process be a tariff, submitted to the Commission by AIC for approval under normal Commission procedures. RGS opines that although a collaborative process should cover operational and program design issues, the Commission should state clearly in this docket its support for the competitive market.

RGS notes that AIC has agreed that the issues identified in Ms. Seckler's testimony regarding developing tariffs supporting mass market retail natural gas competition are appropriate for discussion in workshops and should be addressed, while CUB has stated that it does not oppose a workshop process to formulate a choice program and address issues of concern.

RGS claims there are several elements of RGS' mass market natural gas competition proposal that parties have either agreed to, or at least not disputed during testimony or evidentiary hearings, and thus should not have to be discussed during workshops. RGS indicates that these agreed elements include utility support for the competitive market, full utility cost recovery for the utility, and a properly adjusted price-to-compare. RGS also considers the fair allocation of commodity-related costs an issue to be included, although the parties did not reach agreement about the best method to allocate assets and the assets' costs, RGS states no party disputed that the assets should be allocated in a manner that avoids subsidies and reflects cost causation. Although the parties appear to agree on significant portions of the content of a mass market retail natural gas choice program, RGS indicates the parties still have a number of issues to resolve in the workshop process, although the parties appear open to discussing all open issues in workshops, should they be ordered.

Because no other party has presented evidence promoting different necessary components of a well-designed mass market retail natural gas choice program, RGS urges the Commission to adopt RGS' proposal as the starting point of discussions in its Order, noting that the Commission has used this approach to workshops before to resolve mass market natural gas competitive issues in Peoples and North Shore's 2009 rate case. RGS suggests that this targeted focus on its proposal still allows parties to discuss all relevant issues, but avoids the inefficiency of starting from scratch when the parties could have raised alternative proposals in the present docket.

RGS indicates that no party, other than Staff, appears to oppose the initiation of workshops within one month of the Order in this matter. RGS notes that Staff recommends that the Commission wait until the ORMD releases its report on the natural gas market pursuant to Section 19-130 of the Act. RGS notes that Staff raises three concerns in support of its position, that there is insufficient evidence of empirical benefit of competition in the record, RGS' proposals lack detail, and the ORMD report is pending. RGS submits, however, there is no need for the Commission to postpone the initiation of the workshop process, because all of Staff's concerns are either already addressed by the record in this docket or can be resolved in the workshop process.

While Staff is concerned there is insufficient evidence of the benefits of natural gas choice, RGS submits its witness Mr. Crist has provided or cited to a substantial volume of evidence about the value and benefits of mass market natural gas choice. Notably, Mr. Crist cited to both the Commission's 2007 and 2005 reports on the state of the retail natural gas competitive market, which consisted of empirical observations about the Illinois market, as well as empirical observations from other states in the form of Energy Information Agency and Ohio's experience.

While RGS acknowledges it is impossible to predict the utilities' PGA rate which makes it difficult to quantify dollars and cents customer savings, RGS submits there is value in a choice program that permits customers to have access to a variety of risk-reducing products whose benefits cannot be measured by price differential in any given time period. RGS also disputes that it did not provide sufficient detail for its plan to enact a mass market natural gas choice program. While Staff takes the position that a general rate case does not allows for the comprehensive exchange of information needed to produce a new tariffed service offering, RGS submits this argument underscores the value of the workshop process that RGS recommends. Because the parties have expressed willingness to participate in the workshop process, RGS believes the workshop process would facilitate the necessary exchange of ideas and proposals to create a tariff that benefits all mass market customers. RGS opines that workshops are an appropriate venue for finalizing details for all open issues, which would resolve any lack of detail present in Mr. Crist's testimony.

RGS also suggests that the fact that the ORMD has been directed by the General Assembly to develop a natural gas choice report is not a valid reason for delaying the workshops. RGS notes there is nothing in the legislation that suggests the Commission should defer this decision until the ORMD submits its report; rather, the legislation is entirely consistent with the Commission directing workshops to commence immediately. RGS also notes that the process and timing for the ORMD to develop this report is entirely unknown. RGS indicates that Staff concedes that Section 19-130 does not prevent the Commission from ordering workshops or approving tariffs for a mass market natural gas competition program, but it appears that this would be Staff's preference. As Section 19-130 requires identification and removal of barriers to competition, RGS believes that the ORMD's development of its report would be facilitated by the Commission initiating workshops at the conclusion of the instant proceeding to develop AIC's mass market customer choice program.

RGS submits that Section 19-130 also indicates the General Assembly's expectation that there should be competitive natural gas markets in Illinois. RGS notes the statute repeatedly calls for the ORMD report to identify barriers to the development of competitive gas markets in Illinois, and also calls for the ORMD to identify solutions to those barriers. RGS alleges that the language of Section 19-130 communicates a clear expectation that there should be a competitive market now, and nothing in Section 19-130 suggests any intention by the General Assembly to constrict the development of the competitive market in any respect, and certainly nothing communicates an intention to wait for the issuance of the ORMD report before implementation of choice. RGS suggests that a fair reading of Section 19-130 indicates it is not intended to slow the process, and a recommendation to read it in that manner is unpersuasive and inaccurate.

RGS further notes that no evidence has been presented by Staff of how the process for developing and drafting the ORMD report will work, and Staff witness Rearden acknowledged that he has no idea what the scope, content, or timing will be of the ORMD report. Indeed, RGS notes that Dr. Rearden identified a further fundamental problem with reliance on the ORMD Report process – the date by which the ORMD Report is due is unclear even to Staff, and may not occur until July 2013. RGS suggests that in light of the scope of Section 19-130, it would not make sense to delay the workshop process or the filing of a tariff resulting from that workshop process when Staff cannot articulate a benefit from further delay. RGS recommends that the Commission approve a workshop process on the issue of a SVT program for AIC, to commence within one month of the final order, and to last no longer than six months.

E. ICEA Position

As ICEA understands the record in this proceeding, AIC is not opposed in concept to a retail market gas choice program, yet the ICEA notes the record also shows that AIC and others have expressed some reservations regarding the development of a gas choice program. ICEA asserts these reservations include past complaints brought against certain retail natural gas suppliers, a seeming lack of interest by consumers for such a program, and a desire to see an analysis of the savings such a program could bring. ICEA alleges these concerns have been fully addressed in RGS witness Crist's testimony, therefore ICEA concurs with RGS that the time is right to provide consumers gas choice in the AIC service territory.

ICEA agrees with RGS that a lack of customers requesting a gas choice program is not evidence that a program should not be implemented. ICEA maintains that, just the same as opportunities have been available in utility service territories in northern Illinois, consumers in AIC service territory should be given the same opportunity to benefit from the choices and rate offerings that flow from a properly and well-developed retail gas choice program.

While AG/CUB witness Thomas discusses certain issues regarding existing choice programs in Illinois, ICEA argues his testimony does not reference the 2009 change to the Act. ICEA suggests that it appears from the record that there is support for a retail gas choice program provided that both customer protections and consumer education initiatives are viable components of such a program and that utility cost recovery is appropriate. ICEA agrees with the importance of these matters and the prominence they should take in the workshop discussions.

ICEA notes that AIC indicates it is not planning to develop a residential gas choice program unless mandated by legislation or ordered by the Commission. Given that it would take a Commission Order to move AIC to a choice program, ICEA urges the Commission to include just such a directive in its Order for this proceeding to guarantee a retail gas choice program is put in place. ICEA also recognizes that a hastily-fashioned program is neither in the best interest of customers nor any of the parties, and for this reason, ICEA supports a collaborative approach such as that proposed by RGS, which would allow input from all parties and ensure a wide and full exchange of ideas and specifics. ICEA suggests this type of process would also ensure that the program developed would have the broadest support of all parties involved.

In ICEA's view, developing a gas choice program requires full discussions on program costs with proper allocation and payment for assets; financial security, billing and rate options; capacity; and, dutiful regard for consumer protection and consumer education. ICEA avers that while none of these items are quickly addressed, workshop discussions with no intended end-date may be wasteful of time and encourage delay. As such, ICEA asks that the Commission's order clearly set out both a start date and an end date for the workshops with an ultimate goal to have all parties agree on a functioning gas choice program and with the understanding that any items not agreed-upon will be decided by the Commission. ICEA indicates that CUB and AIC have both indicated that they would be open to a collaborative approach.

F. Commission Conclusion

The Commission notes that it has long had a policy favoring competition in energy markets, and the Commission believes that customers will generally benefit from being given the opportunity to participate in a well-designed competitive market. The Commission also recognizes that the Act also generally supports competition in the market, and that the Commission has consistently advanced this view. In this proceeding, the Commission is presented with RGS and ICEA urging it to continue further down the road toward competitive markets by bringing customer choice to AIC's residential and small commercial customers, while Staff, CUB, and AIC suggest the Commission take a slower approach and await the report from the ORMD, which will apprise the Commission on the state of competition in Illinois' gas and electric markets, as well as barriers to retail competition.

The Commission is troubled, however, when some of the parties suggest that this issue not proceed any further in this docket, and that this issue be addressed following the filing of the ORMD report. The Commission notes that the evidence presented in this docket on the ORMD process appears minimal, with a suggestion by Staff witness Rearden that the report may not be concluded until the middle of 2013, and his indication that he is not sure that Staff will even participate.

The Commission does not agree with the argument that the report from ORMD pursuant to Section 19-130 of the Act should be a prerequisite for development of a mass market natural gas choice program. The Commission finds the language of Section 19-130 to be pro-competition, noting that Section 19-130 appears to presume that there should be competitive markets in Illinois, with an apparent mandate to the ORMD to identify barriers to the development of those competitive markets and propose solutions to eliminate those barriers. The Commission believes it would be contrary to both the letter and the spirit of Section 19-130 to use that section as a reason not to advance competition in Illinois, and we decline to read the section in that manner. In the Commission's view, initiation of a workshop process to develop and implement a mass market natural gas choice program is entirely consistent with Section 19-130, and in no way conflicts with its intent or impinges upon the ORMD report process that it envisions.

While the Commission recognizes that any process, including a workshop, will take time, the Commission believes that this issue would best be addressed by commencing the workshops sooner, rather than later. The Commission acknowledges that there may be some overlap between the conducting of the workshops and the preparation of the ORMD report; however, the Commission suggests the parties may find some synergies available between the two.

The Commission finds it appropriate therefore, to direct Staff to host workshops on the issue of whether an SVT is appropriate for the AIC service territories, with the issues to be covered including those addressed by the parties, which appear to include: whether there would be any benefit to customers from such a program; whether the costs of implementing such a program would be reasonable; whether there is utility support for the competitive market; will there be full utility cost recovery for the utility; and a properly adjusted price-to-compare. The Commission recognizes that there will most certainly be other issues that arise during the workshop process, and the Commission encourages the parties to fully explore these issues. This workshop process is open to all interested stakeholders and should include participation by Staff, including the ORMD.

The Commission recognizes that it has used a workshop process in numerous other instances involving both choice issues as well as other more complex issues. The Commission is of the opinion that a workshop process provides flexibility and open access to all stakeholders to work out development and operational details for a choice program, to consider other examples of choice programs, and to debate and formulate a workable process to implement mass market choice for AIC customers. The Commission expects all parties to work in good faith during the workshop process, and believes that each party involved in this proceeding has expressed just such intent.

With regard to the timing of the workshops, the Commission finds that it would be appropriate for the workshop process to commence within sixty days of the date of this Order. The Commission also finds that a workshop of six months duration should be adequate. The Commission believes this will give all parties a sufficient opportunity to identify and debate any operational issues presented by an SVT; and as CUB notes, to address any needed consumer protections. The Commission hopes that the workshops will allow the parties to have a full opportunity to identify potential issues and reach consensus (to the extent possible). The Commission therefore directs Staff to convene a workshop process within sixty days of this Order, with the workshop open to all interested stakeholders. The workshops should have the goal of developing a consensus on this issue, and the workshops shall conclude with AIC filing a petition within 60 days of the conclusion of the workshops, which petition should include as an exhibit suggested SVT tariffs based on discussions at the workshops. Should the workshop process be unable to develop any consensus as to suggested SVT tariffs, rather than AIC filing a petition, Staff is directed to prepare a report to the Commission detailing the workshop process and the issues and discussions presented by the parties.

By the Commission's action in this Order, the Commission does not intend to prejudge whether and to what extent a natural gas retail choice program may be appropriate for AIC. While the Commission strongly embraces retail competition in the energy markets, the Commission believes it is appropriate to examine and address market barriers and other related issues as the program is being developed, rather than to address them when a program might already be in place. The Commission recognizes that a poorly-executed SVT program could do harm to market entrants and market participants, and might slow the development of a robust natural gas market.

XII. OTHER

A. Rate Zone Schedules in Future Rate Filings

Through the time of hearing, AIC and the Staff disagreed as to whether the order in this case should expressly require AIC to provide cost of service data by Rate Zone in future rate filings. Since the hearing, AIC and Staff have agreed that the order should reflect the following finding:

> 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.

The Commission finds this provision to be appropriate and it is hereby incorporated herein.

B. Original Cost Determination

AIC sought original cost determinations because certain requirements for preservation of records are associated with or related to an original cost determination. AIC recommends the Commission conclude and make a finding in the Order in this proceeding that AIC's plant balances as of December 31, 2009 reflected on AIC Gas Schedule B-5 are approved for purposes of an original cost determination. On rebuttal, Staff agreed that AIC plant balances as of December 31, 2009 should be used, but suggested making the determinations separately by Rate Zone. AIC witness Stafford recalculated Staff's adjustment to adjust amounts to the correct line number on Gas Rate Zone 3. This issue is now resolved and Staff recommends that the order in this proceeding contain the following language in the Findings and Ordering Paragraphs:

> (x) the Commission, based on AIC's gas Rate Zone 1 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 1 as of said date;

(x) the Commission, based on AIC's gas Rate Zone 2 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 2 as of said date; and

(x) the Commission, based on AIC's gas Rate Zone 3 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 3 as of said date.

The Commission finds the suggested original cost determinations to be appropriate, and they will be adopted for use in this proceeding.

C. Depreciation Rate Study

Staff recommends that the Commission order AIC to prepare depreciation studies and file the studies with the Commission within six months of the date of the Order in this proceeding consistent with the Rate Zones established by the Commission in setting rates in this case. Staff proposed the depreciation studies should be conducted prior to AIC's next rate case. AIC indicates that the Commission last established deprecation rates for the former operating utilities in Docket Nos. 07-0585 et al. (Cons.) based upon depreciation studies for individual plant accounts within each of the legacy companies. AIC states that these rates were not necessarily uniform for the same account across each operating utility. AIC notes that prior to the merger, it filed a petition on August 23, 2010 for approval to change to combined, weighted average rates for the combined entity's gas operations. AIC concurs with Staff that new gas depreciation studies are needed, and has reached agreement with Staff that AIC be allowed nine months from the date of the order in this case to conduct and file the studies with the Commission. Nine months from the date of the Order in this proceeding is needed to allow AIC sufficient time to compile and review study data based on AIC utility plant and depreciation reserve balances and related retirement and net salvage experience through year end 2011 utilized in the determination of new depreciation rates. Furthermore, the AIC gas depreciation studies will establish depreciation rates by Commission account or subaccount that will allow for calculation of depreciation expense and allocation of expense to Rate Zones in a manner very similar to the approach used by AIC and Staff in the current rate case.

The Commission agrees with this recommendation, and will direct that AIC prepare new depreciation studies within nine months of the date of this Order, in conformity with the parties agreement.

XIII. FINDINGS AND ORDERING PARGRAPHS

The Commission, having given due consideration to the entire record herein and being fully advised in the premises, is of the opinion and finds that:

(1) AIC is an Illinois corporation engaged in the distribution and sale of electricity and natural gas to the public in Illinois, and is a public utility as defined in Section 3-105 of the Act;

(2) the Commission has jurisdiction over the parties hereto and the subject matter herein;

(3) the recitals of fact and conclusions of law reached in the prefatory portion of this Order are supported by the evidence of record, and are hereby adopted as findings of fact and conclusions of law; Appendices A, B, and C attached hereto provide supporting calculations for those portions of this Order concerning gas operations in Rate Zones 1, 2, and 3, respectively.

(4) the test year for the determination of the rates herein found to be just and reasonable should be the 12 months ending December 31, 2012, as adjusted; such test year is appropriate for purposes of this proceeding;

(5) for purposes of this proceeding, based on AIC's gas Rate Zone 1 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, the net original cost rate base for gas delivery service operations in Rate Zone 1 as of said date is $374,930,000;

(6) for purposes of this proceeding, based on AIC's gas Rate Zone 2 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, the net original cost rate base for gas delivery service operations in Rate Zone 2 as of said date is $519,714,000;

(7) for purposes of this proceeding, based on AIC's gas Rate Zone 3 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, the net original cost rate base for gas delivery service operations in Rate Zone 3 as of said date is $938,504,000;

(8) a just and reasonable return which AIC should be allowed to earn on its net original cost gas delivery service rate base is 8.33%; this ROR incorporates a ROE of 9.06%;

(9) the ROR for Rate Zone 1 set forth in Finding (8) results in base rate gas delivery service operating revenues of $77,317,000 and net annual operating income of $18,637,000 based on the test year approved herein;

(10) the ROR for Rate Zone 2 set forth in Finding (8) results in base rate gas delivery service operating revenues of $78,910,000 and net annual operating income of $15,134,000 based on the test year approved herein;

(11) the ROR for Rate Zone 3 set forth in Finding (8) results in base rate gas delivery service operating revenues of $175,844,000 and net annual operating income of $45,637,000 based on the test year approved herein;

(12) AIC's gas delivery service rates which are presently in effect are insufficient to generate the operating income necessary to permit it the opportunity to earn a fair and reasonable return on net original cost rate base; these rates should be permanently canceled and annulled;

(13) the specific rates proposed by AIC in its initial filings do not reflect various determinations made in this Order regarding revenue requirement, cost of service allocations, and rate design; the proposed rates should be permanently canceled and annulled consistent with the findings herein;

(14) AIC should be authorized to place into effect tariff sheets for Rate Zone 1 designed to produce annual base rate gas delivery service revenues of $77,317,000, which represents an increase of $6,791,000 or 9.63%; such revenues, in addition to other tariffed revenues, will provide AIC with an opportunity to earn the ROR set forth in Finding (8) above; based on the record in this proceeding, this return is fair and reasonable for Rate Zone 1;

(15) AIC should be authorized to place into effect tariff sheets for Rate Zone 2 designed to produce annual base rate gas delivery service revenues of $78,910,000, which represents an increase of $10,657,000 or 15.61%; such revenues, in addition to other tariffed revenues, will provide AIC with an opportunity to earn the ROR set forth in Finding (8) above; based on the record in this proceeding, this return is fair and reasonable for Rate Zone 2;

(16) AIC should be authorized to place into effect tariff sheets for Rate Zone 3 designed to produce annual base rate gas delivery service revenues of $175,844,000, which represents an increase of $14,772,000 or 9.17%; such revenues, in addition to other tariffed revenues, will provide AIC with an opportunity to earn the ROR set forth in Finding (8) above; based on the record in this proceeding, this return is fair and reasonable for Rate Zone 3;

(17) determinations regarding cost of service, interclass revenue allocations, rate design, and tariff terms and conditions, as are contained in the prefatory portion of this Order, are reasonable for purposes of this proceeding; the tariffs filed by AIC should incorporate the rates and rate design set forth and referred to herein;

(18) the new tariff sheets authorized to be filed by this Order shall reflect an effective date not less than five working days after the date of filing, with the tariff sheets to be corrected within that time period if necessary, except as is otherwise required by Section 9-201(b) of the Act as amended;

(19) all motions, petitions, objections, and other matters in this proceeding which remain unresolved should be disposed of consistent with the conclusions herein.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that the tariff sheets at issue in these dockets and presently in effect for gas delivery service rendered by Ameren Illinois Company d/b/a Ameren Illinois are hereby permanently canceled and annulled effective at such time as the new gas delivery service tariff sheets approved herein become effective by virtue of this Order.

IT IS FURTHER ORDERED that the proposed tariffs seeking a general increase in gas delivery service rates, filed by Ameren Illinois Company d/b/a Ameren Illinois on February 18, 2011, are permanently canceled and annulled.

IT IS FURTHER ORDERED that Ameren Illinois Company d/b/a Ameren Illinois is authorized to file new tariff sheets with supporting workpapers in accordance with Findings (14), (15), (16), (17), and (18) of this Order, applicable to gas delivery service furnished on and after the effective date of said tariff sheets.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that subject to the provisions of Section 10-113 of the Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 10th day of January, 2012.

(SIGNED) DOUGLAS P. SCOTT

Chairman

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a	)	**File No. ER-2010-0036**
AmerenUE's Tariffs to Increase Its Annual	)	Tariff No. YE-2010-0054
Revenues for Electric Service	)	

REPORT AND ORDER

Issue Date: May 28, 2010

Effective Date: June 7, 2010

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service	)))	**File No. ER-2010-0036** Tariff No. YE-2010-0054

APPEARANCES

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For the Office of the Public Counsel and the Public.

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For the Missouri Department of Natural Resources.

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For the Midwest Energy Users' Association.

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For Laclede Gas Company.

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For Missouri Energy Group.

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For AARP and the Consumers Council of Missouri.

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For International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, 1455, AFL-CIO and International Brotherhood of Operating Engineers Local 148, AFL-CIO.

Mark W. Comley, Attorney at Law, Newman, Comley & Ruth, 601 Monroe, Suite 301, Jefferson City, Missouri 65102.

For Charter Communications, Inc..

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For the City of O'Fallon, the City of University City, the City of Rock Hill, and the St. Louis County Municipal Group (The Municipal Group).

Douglas L. Healy, Attorney at Law, Healy & Healy, LLC, 939 Boonville, Suite A, Springfield, Missouri 65802.

For the Missouri Joint Municipal Electric Utility Commission

Thomas R. Schwarz, Blitz, Bardgett & Deutsch, L.C. 308 East High Street, Suite 301, Jefferson City, Missouri 65101.

For the Missouri Retailers Association.

CHIEF REGULATORY LAW JUDGE: **Morris L. Woodruff**

REPORT AND ORDER

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The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Summary

This order allows AmerenUE to increase the revenue it may collect from its Missouri customers by approximately $226.3 million based on the data contained in the Revised True-up Reconciliation filed by the Missouri Public Service Commission Staff on April 14, 2010.

Procedural History

On July 24, 2009, Union Electric Company, d/b/a AmerenUE filed tariff sheets designed to implement a general rate increase for electric service. The tariff would have increased AmerenUE's annual electric revenues by approximately $401.5 million. The tariff revisions carried an effective date of August 23, 2009. By a separate tariff also issued on July 24, AmerenUE sought to implement an interim rate adjustment that would have allowed it to recover $37.3 million as an interim rate increase. The interim rate adjustment tariff carried an October 1, 2009 effective date.

By order issued on July 27, 2009, the Commission suspended AmerenUE's general rate increase tariff until June 21, 2010, the maximum amount of time allowed by the controlling statute.[1] In the same order, the Commission directed that notice of AmerenUE's tariff filing be provided to interested parties and the public. The Commission also established August 17, 2009, as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: The International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, and 1455, AFL-CIO and International Union of Operating Engineers Local 148 AFL-CIO (collectively the Unions); The Missouri Industrial Energy Consumers (MIEC);[2] The Missouri Energy Group (MEG);[3] The Missouri Department of Natural Resources; Laclede Gas Company; The Consumers Council of Missouri; AARP; The Missouri Retailers Association; The Natural Resources

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[1] Section 393.150, RSMo 2000.

[2] The following members of MIEC were allowed to intervene as individual entities and as an association: Anheuser-Busch Companies, Inc.; BioKyowa, Inc.; The Boeing Company; Doe Run; Enbridge; General Motors Corporation; GKN Aerospace; Hussmann Corporation; JW Aluminum; MEMC Electronic Materials; Monsanto; Pfizer; Precoat Metals; Proctor & Gamble Company; Nestlé Purina PetCare; Noranda Aluminum; Saint Gobain; Solutia; and U.S. Silica Company.

[3] The members of MEG are Barnes–Jewish Hospital; Buzzi Unicem USA, Inc.; and SSM HealthCare.

Defense Council; the Missouri Association of Community Organizations for Reform Now (MO-ACORN); the City of O'Fallon, the City of University City, the City of Rock Hill, and the St. Louis County Municipal League (the Municipal Group); the Midwest Energy Users' Association (MEUA);[4] Charter Communications, Inc.; the Missouri Joint Municipal Electric Utility Commission; and Kansas City Power & Light Company.

On September 14, 2009, the Commission established the test year for this case as the 12-month period ending March 31, 2009, trued-up as of January 31, 2010. In its September 14 order, the Commission established a procedural schedule leading to an evidentiary hearing regarding AmerenUE's general rate increase tariff.

The Commission addressed AmerenUE's interim rate increase tariff separately. The Commission suspended that tariff from its October 1, 2009 effective date until January 29, 2010. After accepting prefiled testimony and conducting an evidentiary hearing on December 7, 2009, the Commission rejected the interim rate increase tariff in a Report and Order issued on January 13, 2010.

In January and February, 2010, the Commission conducted seventeen local public hearings at various sites around AmerenUE's service area. At those hearings, the Commission heard comments from AmerenUE's customers and the public regarding AmerenUE's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on March 15, 2010, and continued through March 26. The parties indicated they had no contested true-up issues and the Commission cancelled the true-up hearing scheduled for April 12 and 13, 2010.

[4] The members of MEUA are Wal-Mart Stores and Best Buy Co. Inc.

The parties filed post-hearing briefs on April 23, 2010, with reply briefs following on April 30. Based on the revised true-up reconciliation filed by Staff on April 14, 2010, AmerenUE has reduced its rate increase request to $286,930,749.

Pending Motion

Following the hearing, on April 22, Staff and AmerenUE filed a written motion offering certain true-up exhibits into evidence. The written motion was necessary because the true-up hearing was cancelled at the request of the parties. The Commission issued an order on April 23 that established April 26 as the deadline for the parties to object to the admission of any of the submitted exhibits. MIEC filed a response on April 26 entitled Objection to True-Up Reconciliation. Despite its title, MIEC's pleading did not object to the admission of the true-up reconciliation that had been submitted by Staff as exhibit 244. Rather, MIEC's pleading asked the Commission to modify that reconciliation to correctly reflect MIEC's position on steam production – net salvage. The Commission issued an order on April 27 that modified the reconciliation as requested by MIEC and admitted all the true-up exhibits into evidence.

On May 3, AmerenUE filed a motion asking the Commission to modify a portion of its April 27 order admitting the true-up exhibits into evidence by rejecting the modification to the reconciliation offered by MIEC. MIEC filed suggestions in opposition to that motion on May 3.

AmerenUE contends the reconciliation should not be modified to reflect MIEC's asserted position on depreciation because that position is not supported by the evidence in the record. MIEC responds by asserting that its adjustment is correct. The challenged exhibit is simply Staff's reconciliation that purports to evaluate the monetary value of the positions asserted by the various parties. At any rate, AmerenUE's motion indicates its motion will be moot if the Commission uses the life span approach to depreciation advocated by the company. This report and order does use the life span approach advocated by AmerenUE, so the motion is moot. On that basis, AmerenUE's Motion to Modify Order Admitting True-Up Exhibits is denied.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed four nonunanimous partial stipulations and agreements resolving issues that would otherwise have been the subject of testimony at the hearing. No party opposed those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[5] After considering both stipulations and agreements, the Commission approved them as a resolution of the issues addressed in those agreements.[6] The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

On March 17, 2010, the Office of the Public Counsel, Noranda, MIEC, AARP and the Consumers Council of Missouri, and the Missouri Retailers Association filed an additional non-unanimous stipulation and agreement that would have resolved various class cost of service and rate design issues.[7] MEUA opposed that non-unanimous stipulation and agreement, and as provided in the Commission's rules, the Commission will consider that

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[5] Commission Rule 4 CSR 240-2.115(C).

[6] The Commission issued an *Order Approving First Stipulation and Agreement* on March 24, 2010. The Commission issued an *Order Approving Second Stipulation and Agreement, Third Stipulation and Agreement, and Market Energy Prices Stipulation and Agreement* on April 14, 2010.

[7] The same parties filed an addendum to their stipulation and agreement on March 26, 2010. MEUA also opposed that addendum.

stipulation and agreement to be merely a position of the signatory parties to which no party is bound.[8] The issues that were the subject of that stipulation and agreement will be determined in this report and order.

Overview

AmerenUE is an investor-owned integrated electric utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. AmerenUE has approximately 1.2 million retail electric customers in Missouri, more than 1 million of whom are residential customers.[9] AmerenUE also operates a natural gas utility in Missouri but the rates it charges for natural gas are not at issue in this case.

AmerenUE began the rate case process when it filed its tariff on July 24, 2009. In doing so, AmerenUE asserted it was entitled to increase its retail rates by $401.5 million per year, an increase of approximately 18 percent.[10] AmerenUE attributed approximately $227 million of that increase to the rebasing of fuel costs that would otherwise be passed through to customers by operation of the company's existing fuel adjustment clause.[11] AmerenUE set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on July 24. In addition to its filed testimony, AmerenUE provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review AmerenUE's testimony and records to determine whether the requested rate increase was justified.

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[8] Commission Rule 4 CSR 240-2.115(2)(D).

[9] Baxter Direct, Ex. 100, Page 4, Lines 14-15.

[10] Baxter Direct, Ex. 100, Page 5, Lines 7-8.

[11] Baxter Direct, Ex. 100, Page 5, Lines 8-11.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On March 8, the parties filed a list of the issues they asked the Commission to resolve.

As previously indicated, a number of the identified issues were resolved by the approved partial stipulations and agreements and will not be further addressed in this report and order. The remaining issues will be addressed in turn.

Conclusions of Law Regarding Jurisdiction

A. AmerenUE is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Supp. 2009). As such, AmerenUE is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

B. Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates AmerenUE may charge its customers for electricity. When AmerenUE filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

Conclusions of Law Regarding the Determination of Just and Reasonable Rates

A. In determining the rates AmerenUE may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[12] AmerenUE has the burden of proving its proposed rates are just and reasonable.[13]

[12] Section 393.150.2, RSMo 2000.

B. In determining whether the rates proposed by AmerenUE are just and reasonable, the Commission must balance the interests of the investor and the consumer.[14] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[15]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[16]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated.

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[13] *Id.*

[14] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).

[15] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

[16] *Id*. at 692-93.

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[17]

C. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[18]

D. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[19]

The Rate Making Process

The rates AmerenUE will be allowed to charge its customers are based on a determination of the company's revenue requirement. AmerenUE's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can

[17] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

[18] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).

[19] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return
R = Return requirement
(V-AD+A) = Rate base
For the rate base calculation:
V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

The Issues

1. Rate of Return

Findings of Fact:

Introduction:

1. This issue concerns the rate of return AmerenUE will be authorized to earn on its rate base. Rate base includes things like generating plants, electric meters, wires and poles, and the trucks driven by AmerenUE's repair crews. In order to determine a rate of return, the Commission must determine AmerenUE's cost of obtaining the capital it needs.

a. Capital Structure

2. The relative mixture of sources AmerenUE uses to obtain the capital it needs is its capital structure. All parties agree that AmerenUE's actual capital structure as of the true-up date, January 31, 2010, should be used for purposes of establishing its rates in this case. Staff's True-Up Accounting Schedules described AmerenUE's actual capital structure as of January 31, 2010 as:

Long-Term Debt 47.26%

Short-Term Debt	00.00%
Preferred Stock	01.48%
Common Equity	51.26%[20]

Since all parties accept this capital structure, the Commission will not further address this matter.

3. Similarly, AmerenUE's calculation of the cost of its long-term debt and preferred stock is not disputed by any party,[21] and will not be further addressed.

b. Return on Equity

Introduction:

4. Determining an appropriate return on equity is without a doubt the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them.[22] In contrast, in determining a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in AmerenUE rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for AmerenUE's ratepayers. In order to obtain guidance about the

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[20] Staff True-Up Accounting Schedules, Ex. 243, Schedule 12.

[21] Transcript, Page 1953, Lines 3-5.

[22] Lawton Direct, Ex. 304, Page 9, Lines 4-5.

appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

5. Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Dr. Roger A. Morin testified on behalf of AmerenUE. Dr. Morin is Emeritus Professor of Finance at Robinson College of Business, Georgia State University, and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. He holds a Bachelor of Engineering degree and an MBA in Finance from McGill University, as well as a Ph.D. in Finance and Econometrics from the Wharton School of Finance, University of Pennsylvania.[23] He recommends the Commission allow AmerenUE a return on equity of 10.8 percent.[24]

6. David Murray testified on behalf of Staff. Murray is the Acting Utility Regulatory Manager of the Financial Analysis Department for the Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri – Columbia, and a MBA from Lincoln University. Murray has been employed by the Commission since 2000 and has offered testimony in many cases.[25] Murray recommends a return on equity within a range of 9.0 percent to 9.7 percent,[26] with a recommended midpoint of 9.35 percent.[27]

7. Stephen G. Hill also offered rate of return testimony on behalf of Staff. Hill is self-employed as a financial consultant, specializing in financial and economic issues in regulated industries. He earned a Bachelor of Science degree in Chemical Engineering from Auburn University, and a Masters degree in Business Administration from Tulane

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[23] Morin Direct, Ex. 111, Page 1, Lines 6-16.

[24] Morin Rebuttal, Ex. 112, Page 52, Line 13.

[25] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Appendix 1, Page 42.

[26] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Page 37, Lines 24-26.

[27] Transcript, Page 2022, Lines 24-25.

University.[28] Hill did not offer a recommended a return on equity for AmerenUE. Instead, he offered testimony to support Murray's recommended rate of return, and to rebut the testimony offered by the other testifying return-on-equity witnesses.[29]

8. Michael Gorman testified on behalf of MIEC. Gorman is a consultant in the field of public utility regulation.[30] He holds a Bachelors of Science degree in Electrical Engineering from Southern Illinois University and Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[31] Gorman recommends the Commission allow AmerenUE a return on equity within a range of 9.5 percent to 10.5 percent, with a recommended midpoint of 10.0 percent.[32]

9. Finally, Daniel J. Lawton testified on behalf of Public Counsel. Lawton is a consultant who holds a Bachelor of Arts degree in Economics from Merrimack College and a Master of Arts in Economics from Tufts University.[33] Lawton recommends the Commission allow AmerenUE a return on equity within a range of 9.3 percent to 10.9 percent,[34] with a recommended midpoint of 10.1 percent.[35]

Specific Findings of Fact:

10. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and stock

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[28] Hill Rebuttal, Ex. 212, Page 1, Lines 7-15.

[29] Hill Surrebuttal, Ex. 213, Pages 22-23, Lines 20-26, 1-23.

[30] Gorman Direct, Ex. 408, Page 1, Line 5.

[31] Gorman Direct, Ex. 408, Appendix A, Page 1, Lines 10-12.

[32] Gorman Direct, Ex. 408, Page 2, Lines 9-11.

[33] Lawton Direct, Ex. 304, Schedule DJL-1.

[34] Lawton Direct, Ex. 304, Page 5, Lines 11-12.

[35] Transcript, Page 2186, Lines 15-17.

price appreciation[36] Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method assumes the current market price of a firm's stock is equal to the discounted value of all expected future cash flows. The Risk Premium method assumes that all the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium to compensate the investor for the risks of investing in equities compared to bonds. The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio. No one method is any more "correct" than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

11. Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at another number. For 2009, the average return on equity awarded to integrated electric utilities by state commissions in this country was 10.59 percent, as reported by Regulatory Research Associates.[37]

12. The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on equity to AmerenUE. However, AmerenUE must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

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[36] Gorman Direct, Ex. 408, Page 15, Lines 10-12.

[37] Morin Rebuttal, Ex. 112, Page 2, Lines 11-14.

13. In his direct testimony filed on behalf of AmerenUE, which he submitted in July 2009, Dr. Morin recommended AmerenUE be allowed a return on equity of 11.5 percent.[38] By February 11, 2010, when he submitted his rebuttal testimony, Dr. Morin had reduced this recommended return on equity to 10.8 percent.[39] Dr. Morin did not change his methodology, but his updated analysis used December 2009 stock prices that were higher than the prices he had used in his July 2009 testimony.[40] He testified that his rebuttal testimony was intended to supersede his direct testimony[41] and that a recommendation of 11.5 percent would be ludicrous at the time of the hearing.[42] The Commission will consider Dr. Morin's recommendation of 10.8 percent when deciding an appropriate return on equity for AmerenUE.

14. Three of the four return on equity experts offered recommendations between 10.0 percent and 10.8 percent. The fourth recommendation, the 9.35 percent recommended by Staff's witness David Murray, is lower than the other recommendations, and is substantially lower than the 2009 national average of allowed returns on equity of 10.59 percent.[43]

15. Murray's recommendation is low because the three stage DCF analysis he performed relies on an unreasonably low long-term growth estimate of 3.1 percent. Murray based his long-term growth rate on the Energy Information Administration's projection of long-term growth in the usage of electricity plus an inflation factor.[44] Murray's calculation of

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[38] Morin Direct, Ex. 111, Page 5, Lines 17-20.

[39] Morin Rebuttal, Ex. 112, Page 56, Lines 9-11.

[40] Morin Rebuttal, Ex. 112, Pages 52-53.

[41] Transcript, Page 1828, Lines 1-4.

[42] Transcript, Page 1898, Lines 19-20.

[43] Morin Rebuttal, Ex. 112, Page 6, Lines 22-28.

[44] Staff Report – Revenue Requirement/Cost of Service, Pages 26-27, Lines 6-28, 1-8.

a long-term growth rate based on the anticipated growth of demand for electricity is inconsistent with the requirements of the DCF model, which relies on earnings/dividends growth.[45] If Murray had instead relied on the historical growth in real GDP for the United States from 1929 through 2008, plus an inflation factor, he would have derived a long-term growth forecast of 6.0 percent.[46]

16. Murray's DCF analysis also contrasts sharply with the DCF analysis performed by the other return on equity experts, who relied on forecasted growth rates published by reputable investment analysts. As Public Counsel's witness, Daniel Lawton, explained at the hearing, the growth in the use of electricity is not a good measure of the actual growth in an electric utilities earnings because earnings growth can come from more than just the growth in the demand for electricity.[47] Lawton also defended his, and other analyst's use of forecasted growth rates, testifying: "relying on published price, dividend and growth rate data and forecasts is not different or unique. … this is what regulatory authorities typically consider to determine a reasonable return for setting fair and just rates for consumers."[48] Lawton testified that he would never use projected growth in electricity demand as a component in the growth rate in a DCF analysis so long as analyst forecasts were available[49] and that he has never seen another analyst use such a projection in the way Murray used it.[50]

[45] Morin Rebuttal, Ex. 112, Page 18, Lines 1-2.
[46] Morin Rebuttal, Ex. 112, Page 18, Lines 6-22.
[47] Transcript, Page 2183, Lines 19-25.
[48] Lawton Surrebuttal, Ex. 306, Page 5, Lines 15-18.
[49] Transcript, Page 2211, Lines 8-15.
[50] Transcript, Pages 2210-2211, Lines 12-25, 1-7.

17. In an attempt to support the reasonableness of his very low return on equity recommendation, Murray cites several analyst reports that suggest they anticipate AmerenUE will earn a return on equity of under 9 percent.[51] As further support, Murray points to information from the Missouri State Employees' Retirement System's website that would indicate the pension fund expects future returns on equities of only 8.5 percent.[52]

18. Murray's reliance on analyst reports to support his recommendation is misplaced. Most investors do not have access to the specific analyst reports that Murray examined and thus they cannot rely on them in deciding where to invest their money.[53] More fundamentally, the analyst reports upon which Murray relies are designed to project what the analyst expects a company to earn, not what would be a reasonable return for the company to earn.[54] In other words, an analyst may conclude that AmerenUE will not earn a reasonable return and recommend that investors not invest in that company. That analyst's projection should not then be used to test the reasonableness of a recommendation of the amount a company will need to earn to attract investment.

19. Similarly, Murray's use of information about the investment expectations of a state pension fund to test the reasonableness of his recommendation is not appropriate. Murray indicated he is not aware of any other analyst who uses such information in that manner;[55] although Staff's other return on equity witness, Stephen Hill, recently had a similar

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[51] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Pages 31-35.

[52] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Page 35, Lines 20-27.

[53] Transcript, Page 2213, Lines 4-24.

[54] Transcript, Page 2298, Lines 3-11.

[55] Transcript, Page 2058, Lines 2-8.

argument rejected by the California PUC.[56] The problem with using a pension fund's expectations in this way is that pension funds have different investment goals and thus are not well suited to assessing the cost of equity capital in a rate proceeding.[57]

20 The Commission finds that Staff's recommended return on equity of 9.3 percent is not an appropriate return on equity for AmerenUE.

21. The other three witnesses who recommend rates of return used similar methods of analysis and achieved similar results.[58] The recommendations offered by Gorman for MIEC and Lawton for Public Counsel are very close to each other, with Gorman at 10.0 percent and Lawton at 10.1 percent. Dr. Morin is higher at 10.8 percent.

22. Part of the reason Dr. Morin's recommendation is higher than the other recommendations is that the only DCF model he relied on was a constant growth DCF model. As Gorman explained in describing why he did not rely on this own constant growth DCF results that showed a return on equity of 11.2 percent, "the constant growth DCF return is not reasonable and represents an overstated return for AmerenUE at this time."[59] He went on to explain that the constant growth DCF result is overstated because it is based on a unsustainably high dividend yield and median growth rate.[60] Morin's constant growth DCF suffers from the same deficiencies as Gorman described for his own constant growth analysis.[61]

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[56] Morin Rebuttal, Ex. 112, Page 26, Lines 1-30, *citing, In re S. Cal Edison Co.,* 262 P.U.R. 4th 53, 72 (Ca. Pub. Utils. Comm'n. 2007).

[57] Morin Rebuttal, Ex. 112, Pages 26-27, Lines 33-34, 1-5., *see also,* Transcript, Page 2212, Lines 4-19.

[58] Transcript, Page 1839, Lines 8-13.

[59] Gorman Direct, Ex. 408, Page 24, Lines 11-12.

[60] Gorman Direct, Ex. 408, Page 24, Lines 12-16.

[61] Gorman Rebuttal, Ex. 409, Page 10, Lines 1-6.

23. Gorman and Lawton took those deficiencies into account and based their recommendations on additional sustainable growth DCF and multi-stage DCF models. Gorman's sustainable long-term growth rate resulted in a median DCF return of 10.2 percent,[62] while his multi-stage growth rate resulted in a DCF return of 10.16 percent.[63] Lawton's two-stage DCF analysis showed a cost of equity between 10.2 and 10.4 percent,[64] compared to the 10.9 to 11.1 percent cost of equity shown by his constant growth DCF analysis.[65]

24. In contrast, despite his belief that it is important to "use a whole bunch of techniques",[66] Morin relied on his constant growth DCF analysis and did not analyze any other form of DCF. However, in his rebuttal testimony, Gorman reworked Morin's constant growth DCF analysis as a multi-stage growth analysis, using updated stock price data, current dividends and recent analysts' growth rate estimates. Gorman arrived at a 10.0 percent cost of equity, which is 56 basis points lower than his similar reworking of Morin's constant growth DCF analysis.[67] All three analysts balanced the results of their DCF analysis with risk premium and CAPM analyses that ranged between the low to mid 9 percent and the low ten percent area. Thus, the chief difference between their recommendations is their non-constant growth analyses. Therefore, it is reasonable to believe that if Dr. Morin had performed a multi-stage DCF analysis, as he should have, his recommendation might be in the low 10 percent area along with Gorman and Lawton.

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[62] Gorman Direct, Ex. 408, Page 31, Lines 13-14.
[63] Gorman Direct, Ex. 408, Page 34, Lines 5-8.
[64] Lawton Direct, Ex. 304, Page 25, Lines 19-21.
[65] Lawton Direct, Ex. 304, Page 24, Lines 15-16.
[66] Transcript, Page 1890, Lines 23-24.
[67] Gorman Rebuttal, Ex. 409, Page 12, Lines 1-8.

25. Based on its consideration of the testimony of all the experts, the Commission finds that a return on equity of 10.1 percent is a fair and reasonable return on equity for AmerenUE at this time. That is the return on equity recommended by Lawton and the Commission finds that Lawton was the most credible and reliable expert witness. However, 10.1 percent is a reasonable return on equity aside from the fact that it happens to match the recommendation of one of the witnesses. The Commission's decision to use the return on equity recommended by Lawton should not be taken to disparage the credibility of the other witnesses.

26. A return on equity of 10.1 percent is somewhat lower than the 10.59 percent 2009 average return on equity awarded to integrated electric utilities by state commissions. However, as Dr. Morin and the other expert witnesses indicated, economic facts have changed substantially since 2009. Dr. Morin's own recommendation dropped 70 basis points between July 2009 and February 2010 due to changes in the capital market.[68] Therefore, a slight reduction in allowed return on equity from the 2009 average is reasonable.

Conclusions of Law:

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate

[68] Transcript, Page 1827, Lines 9-21.

> to the particular application' (quoting *Southwestern Bell Telephone Company v. Arkansas Public Service Commission,* 593 S.W. 2d 434 (Ark 1980).[69]

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[70]

B. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[71]

Decision:

Based on the evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 10.1 percent is a fair and reasonable return on equity for AmerenUE. The Commission finds that this rate of return will allow AmerenUE to compete in the capital market for the funds needed to maintain its financial health.

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[69] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[70] *Id.*

[71] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

2. Depreciation

Findings of Fact:

Introduction to Depreciation Issues:

1. Depreciation is the means by which a utility is able to recover the cost of its investment in its rate base by recognizing the reduction in value of that property over the estimated useful life of the property. Depreciation rates should be designed to allow the utility to recover, over the average service life of the assets in that account, the original cost of the assets, plus an estimate of any cost to remove the asset, less scrap value of the asset.[72]

2. The fundamental goal of depreciation is to ensure that the correct amount of depreciation is recovered from each generation of customers over the actual service life of the property.[73] If a depreciation rate is set too high, an excess amount will be recovered from current customers. If a depreciation rate is set too low, the cost of the asset will not be fully recovered during its life, and the unrecovered cost will be dumped on the customers receiving service at the time the asset is retired.

3. The parties disagreed about several aspects of depreciation. The most fundamental disagreement is about whether to use a life span or a mass property approach to determine an appropriate depreciation rate for AmerenUE's steam and hydraulic electric production plant accounts. That is the first depreciation issue the Commission will address.

a. Use of Life Span Versus Mass Property Approach to Determine Depreciation Rates for Steam and Hydraulic Plant Accounts

Introduction:

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[72] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Page 96, Lines 9-11.

[73] Wiedmayer Rebuttal, Ex. 105, Page 15, Lines 2-5.

4. John Wiedmayer, a consultant with Gannet Fleming, Inc., sponsored the depreciation study submitted by AmerenUE[74] His depreciation study uses a life span approach for determining appropriate depreciation rates for steam and hydraulic plant accounts. The steam and hydraulic plants to which these depreciation rates would apply, are AmerenUE's four coal-fired steam generating electric plants, the Meramec, Sioux, Labadie, and Rush Island stations, and hydraulic generating plants at Osage (Bagnall Dam), Keokuk, and Taum Sauk.

5. Arthur Rice, a Utility Regulatory Engineer I for the Commission sponsored a depreciation study submitted by Staff.[75] Staff's depreciation study treats all steam production and all hydraulic plant as mass property.

6. James Selecky, a consultant with Brubaker & Associates,[76] and William Dunkel, a consultant with William Dunkel and Associates,[77] offered testimony on behalf of MIEC that proposed adjustments to the depreciation studies of both AmerenUE and Staff. Selecky advocated the use of a mass property approach because this Commission has used that approach in the past. As an alternative, Selecky suggested modifications to AmerenUE's life span approach if the Commission decided to use that approach.

7. The life span approach to depreciation is premised on the fact that the equipment in a power plant does not remain unchanged during the life of the plant. Instead, interim additions, replacements, and retirements occur regularly throughout the life of the plant.[78] For example, a particular valve on a boiler might have an estimated service life of 50 years.

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[74] Wiedmayer Direct, Ex. 104, Page 1, Lines 10-11.

[75] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Appendix 1. Page 51.

[76] Selecky Direct, Ex. 404 NP, Page 1, Lines 5-6.

[77] Dunkel Rebuttal, Ex. 407, Page 1, Lines 6-7.

[78] Wiedmayer Direct, Ex. 104, Page 5, Lines 9-10.

A depreciation rate for that valve would be set accordingly. In a power plant that went into service in 1960, that valve might be replaced in 2010 with a new valve that again has an estimated service life of 50 years. However, the valve installed into the plant in 2010 has been installed in a power plant that is already 50 years old. If it is assumed that the entire power plant will be retired when it is 60 years old, in 2020, the estimated service life of the valve installed in 2010 will have to be truncated at 10 years. Thus, the depreciation rate for that valve will need to be set to recover its cost over 10 years instead of 50. The life span approach reflects the unique average service lives that are experienced by each year of installation by recognizing the amount of time remaining between the year of installation and the anticipated final retirement of the power plant.

8. For purposes of its life span depreciation study, AmerenUE engaged the services of Black & Veatch Corporation to prepare a study to estimate the retirement dates for its steam powered electric plants.[79] Larry Loos, a Professional Engineer employed by Black & Veatch, sponsored that study through his testimony. The Black & Veatch study estimated the following retirement dates for AmerenUE's steam generating plants:

Meramec	2022
Sioux	2033
Labadie – Units 3 and 4	2038
Labadie – Units 1 and 2	2042
Rush Island	2046[80]

[79] Loos Direct, Ex. 107, Page 5, Lines 18-19.

[80] Loos Direct, Ex 107, Page 14, Lines 2-8.

9. To estimate retirement dates for the hydraulic plants, AmerenUE assumed that the plants would be retired when the operating licenses for the plants expire.[81] The resulting estimated retirement dates for the hydraulic plants are as follows:

Osage	2047
Keokuk	2055
Taum Sauk	2049[82]

10. Staff contends that estimated retirement dates for power plants are inherently unreliable. For that reason, Staff advises the Commission to use a mass property approach to establish depreciation rates for those accounts. Under a mass property approach, all steam plant property from all the plants is examined in a single mortality study. That single study does not differentiate between interim and final retirements; all retirements are considered when determining an estimated service life for the property. Because final retirements that occur when an entire power plant is retired are included in the mix, Staff contends the early retirement of some property will be taken into account when depreciation rates are established.[83]

Specific Findings of Fact:

11. There is nothing wrong with the use of a mass property approach in theory. For some items of property it is perfectly appropriate and is properly used for many purposes in the depreciation studies of both AmerenUE and Staff. For example, the mass property approach is used to determine depreciation rates for items such as poles, meters, and line transformers. Every year AmerenUE adds thousands of poles, meters, and line

[81] Wiedmayer Rebuttal, Ex. 105, Page 12, Lines 3-12.

[82] Wiedmayer Direct, Ex. 104, Schedule JFW-E1, Page III-6.

[83] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Page 104, lines 1-29.

transformers to its system. Those individual poles may be retired at any age, depending upon accidents, lightning strikes, road construction, insect damage, or any number of independent causes.[84] The key point is that the life of each pole is independent of other poles. One may be hit by a truck when it is only one year old, while another may still be in service 60 years later. But there are enough poles in service to allow for a meaningful study to determine how long an average pole will remain in service and establish a depreciation rate accordingly.

12. The problem with treating power plant equipment as mass property is that retirements of large electric power plants are rare events. When Staff's witness examined AmerenUE's property retirement data, that data included final retirement data from only four steam plants, Mound, Cahokia, Venice 1 and Venice 2.[85] The first three of those retired plants were old, small, and inefficient plants retired in the 1970s.[86] Venice 2 was retired in 2002 after a fire.[87] Furthermore, there is very little retirement date available from even those plants because the dollars involved are very small compared to AmerenUE's investment in its current steam plants.[88] There is no final retirement data for the hydraulic plants, as AmerenUE has never shut down a hydraulic plant.[89]

13. Thus, the available retirement data for AmerenUE's steam and hydraulic plants is only indicative of interim retirements that occur during the life of the power plants and fails to provide any useful information about final retirements. As a result, a mass property

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[84] Wiedmayer Rebuttal, Ex. 105, Page 8, Lines 6-12.

[85] Transcript, Page 1384, Lines 11-16.

[86] Selecky Rebuttal, Ex. 405, Page 4, Lines 1-14. See also, Wiedmayer, Surrebuttal, Ex. 106, Page 4-5, lines 21-23, 1.

[87] Selecky Rebuttal, Ex. 405, Pages 4-5, Lines 15-24, 1-5.

[88] Transcript, Pages 1384-1385, Lines 21-25, 1-2.

[89] Transcript, Page 1385, Lines 3-8.

analysis will overstate the average service life of the steam plant property.[90] Indeed, when cross-examined, Staff's witness agreed that he did not have enough data to obtain a true mass property result for the steam or hydraulic plants.[91]

14. The problem of a lack of reliable data is likely the reason all authority cited by the parties states that life span is the appropriate method to use in determining depreciation rates for power plant accounts. *Public Utility Depreciation Practices*, published in 1996 by the National Association of Regulatory Utility Commissioners (NARUC), specifically states that electric power plants are to be treated as life span property.[92] Similarly, the leading textbook on depreciation accounting, *Depreciation Systems*, written by Dr. Frank Wolf and Dr. Chester Finch, clearly indicates that electric generating equipment is to be depreciated using a life span approach instead of a mass property approach.[93] Even Staff's own depreciation manual, which Staff's witness relied upon in preparing his depreciation study,[94] indicates the life span approach is appropriately used to determine depreciation for electric power plants.[95]

15. Not surprisingly, given the support in the literature for the use of the life span approach when determining depreciation rates for electric power plant property, it appears that every other state commission around the country uses the life span approach for

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[90] Wiedmayer Surrebuttal, Ex. 106, Page 9, Lines 1-11.

[91] Transcript, Page 1385, Lines 9-16.

[92] Wiedmayer Rebuttal, Ex. 105, Pages 12-13, Lines 13-25, 1-4.

[93] Wiedmayer Rebuttal, Ex. 105, Page 13, Lines 6-25.

[94] Transcript, Page 1362, Lines 17-21.

[95] *Contents & Outline of a Depreciation Study*, Ex. 231, Pages 44-45. Specifically, that manual states: "Unlike mass utility property such as poles, mains, conductors, etc. there exists utility property that requires some forecast as to its date of retirement. Types of plant applicable to this type of analysis are buildings, *electric power plants*, telephone switching equipment, gas storage fields, etc." (emphasis added).

electrical production facilities.[96] Unfortunately, it appears that the only state commission that has used a mass property approach to determine depreciation rates for electric production facilities is this commission. In an earlier AmerenUE rate case, ER-2007-0002[97], the Commission authorized the use of a mass property approach for electric production facilities. The Commission did so because of frustration over the inadequate evidence AmerenUE presented to establish reasonably likely retirement dates for its electric power plants.

16. In that earlier case, AmerenUE initially estimated that all its power plants would be retired in 2026. After the other parties criticized that retirement date as arbitrary, the company arbitrarily estimated that all its power plants would be retired 60 years after they went on line. In accepting Staff's proposed mass property proposal in that case, the Commission said "without better evidence of when those plants are likely to be retired, allowing the company to increase its depreciation expense based on what is little more than speculation about possible retirement dates would be inappropriate."[98] Thus, the Commission authorized the use of a mass property approach in that particular case, but did not reject the life span approach in general.

17. For this case, AmerenUE presented a detailed study by Black & Veatch that presented thoughtfully calculated retirement dates for each of its coal-fired steam production plants. Those estimated retirement dates would retire the steam production

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[96] Wiedmayer Direct, Ex.104, Pages 30-31, Lines 5-23, 1-10.

[97] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area,* Report and Order, Case No. ER-2007-0002, May 22, 2007.

[98] *Id*. at Page 84.

plants after between 61 and 72 years of service,[99] which is on the high-end of estimated retirement dates used for life span analysis for other utilities by other state commissions.[100]

18. Aside from a proposal to extend the life span of the Meramec unit, which will be addressed in detail later in this Report and Order, MIEC's expert witness, James Selecky, agreed that the Black & Veatch study produced reasonable retirement dates that he used to develop his own life span depreciation rates. He also agreed that the Black & Veatch study was reasonable and logical, and substantially better than the approach AmerenUE used in ER-2007-0002.[101]

19. Staff's expert witness, Arthur Rice, agreed that the Black & Veatch study is "relatively complete and logical" and "well done".[102] He also agreed that the estimated retirement dates presented by AmerenUE are "reasonable."[103] Although Staff's brief claims that AmerenUE's estimated retirement dates are unreliable because AmerenUE did not perform an economic study regarding the retirement of those plants, the number of assumptions and the nature of the assumptions required to make such an economic analysis for events that will happen 12 to 37 years in the future, render such analysis impractical.[104]

20. The Black & Veatch study does not independently establish retirement dates for AmerenUE hydraulic production plants. Instead, AmerenUE's life span study assumes that

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[99] Selecky Direct, Ex. 404 NP, Schedule JTS-2.
[100] Transcript, Page 1482, Lines 14-21.
[101] Transcript, Page 1483, Lines 3-23.
[102] Transcript, Page 1397, Lines 2-12.
[103] Exhibit 168.
[104] Loos Surrebuttal, Ex. 108, Page 8, Lines 9-11.

those plants will be retired when their operating licenses expire.[105] That is the same assumption the Commission has previously used to estimate the retirement date of AmerenUE's Callaway nuclear production plant for purposes of a life span depreciation calculation.[106] AmerenUE's estimated retirement dates would have Taum Sauk retire after 86 years of service, Osage after 94 years of service, and Keokuk after 142 years of service.[107]

21. There is no way to know for sure when the hydraulic plants will be retired. The same can be said about the steam production plants. But it is unreasonable to assume that the plants will last forever. As previously indicated, a mass property approach is not appropriate because of the lack of available retirement data upon which such a study could be based. A life span depreciation study requires an estimated retirement date and the assumed retirement dates for the hydraulic plants are reasonable.

22. It is important to remember that the assumed retirement dates for purposes of a depreciation study are not fixed forever and certainly do not mean that the plant will actually be retired on the assumed retirement date. Future depreciation studies in future rate cases may rely on different estimated retirement dates as further information becomes available and circumstances change. Ultimately, depreciation rates will be adjusted to match the new information so that the correct amount of depreciation is recovered from each generation of customers over the actual service life of the property.

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[105] Wiedmayer Rebuttal, Ex. 105, Page 12, Lines 3-12.

[106] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area,* Report and Order, Case No. ER-2007-0002, May 22, 2007, Pages 87-88.

[107] Selecky Direct, Ex. 404 NP, Schedule JTS-2.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission finds that it is appropriate to use a life span approach to determine depreciation rates for AmerenUE's steam and hydraulic electric production accounts. The Commission finds that the estimated retirement dates proposed by AmerenUE for that purpose are reasonable, with the exception of the retirement date for the Meramec steam production plant, which is addressed later in this order.

b. Proposed Extension of the Lifespan of the Meramec Plant

Findings of Fact:

Introduction:

23. AmerenUE currently operates the Meramec coal-fired steam production plant, located southeast of St. Louis, at the confluence of the Meramec and Mississippi Rivers. The Meramec Generating Station has four pulverized coal subcritical power generating units. Units 1 and 2 were built in 1953 and 1954 respectively; each has a capacity of 138 MW. Unit 3, which has a capacity of 289 MW, was built in 1959, while Unit 4, which has a capacity of 359 MW, was built in 1961.[108] The Black & Veatch study upon which AmerenUE relies to calculate depreciation rates for its steam production plant estimates that AmerenUE will retire its Meramec coal-fired steam production plant in 2022.[109] MIEC's

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[108] Loos Direct, Ex. 107, Schedule LWL-E1, Appendix B, Page B-2.

[109] Loos Direct, Ex. 107, Page 14, Line 4.

witness, James Selecky, contends the estimated retirement date for the Meramec plant should be extended by five years to 2027.[110]

Specific Findings of Fact:

24 There are two reasons the estimated retirement date for the Meramec plant should be extended. First, AmerenUE forecasts an average life span for its other steam production units of approximately 69 years. AmerenUE's predicted life span for Meramec Unit 3 is only 63 years, with a predicted life span for Meramec Unit 4 of 61 years. Extending the predicted life span of Meramec by five years would bring it more in line with the predicted life span of the other coal-fired plants.[111]

25. Second, the Black & Veatch study, upon which AmerenUE based its predicted life spans, indicates that its choice of an expected retirement date for the Meramec plant is based, at least in part, on the assumptions of AmerenUE's Integrated Resource Plan.[112] That plan assumed that AmerenUE would build a second nuclear reactor at its Callaway plant to replace the capacity of the Meramec plant,[113] but AmerenUE is no longer planning to build Callaway 2,[114] and has no plans on how to replace the Meramec plant's capacity.[115] That implies that AmerenUE may keep Meramec in operation beyond 2022.

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[110] Selecky Direct, Ex. 404 NP, Page 22, Lines1-15.

[111] Selecky Direct, Ex. 403HC, Page 22, Lines 3-8.

[112] Loos Direct, Ex. 107, Page 14, Lines 1-13. The Black & Veatch study is attached to Loos' direct as Schedule LWL-E1. The study's reference to the IRP filing is found at page 3-4 of the schedule.

[113] Transcript, Page 1286, Lines 14-18.

[114] Birk Rebuttal, Ex. 103, Page 12, Lines 16-.

[115] Transcript, Page 1286, Lines 19-22.

26. Indeed, the study prepared for AmerenUE by Burns & McDonnell Engineering Company indicates the Meramec plant could be kept in operation substantially past 2022 if its capacity is needed and if its operation is economically viable.[116]

27. Of course, no one can know for certain whether the continued operation of the Meramec plant beyond 2022 will be economically viable. As AmerenUE's own witness testified, the number of assumptions and the nature of the assumptions required make that sort of economic analysis impractical.[117] AmerenUE's estimated retirement dates are not set in stone and may change in a future depreciation study as more information becomes available. But based on the evidence presented, the Commission finds that it is reasonable to assume an additional five years of life for the Meramec plant. This adjustment will reduce AmerenUE's revenue requirement by approximately $10 million.[118]

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

AmerenUE shall calculate depreciation for its steam production plant based on the assumption that the Meramec steam production plant will be retired in 2027.

c. Net Salvage Percentage for Account 312 Boiler Equipment

Findings of Fact:

Introduction:

28. Net salvage is the salvage value of property retired, less the cost of removal. Net salvage value is positive if the salvage value exceeds removal cost and negative if removal

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[116] Ex 434 HC, Page 5-2. The entire exhibit is highly confidential so the Commission will not disclose the details of the report.

[117] Loos Surrebuttal, Ex. 108, Page 8, Lines 9-11.

[118] Transcript, Page 1523, Lines 14-19.

costs exceed the salvage value.[119] AmerenUE chose not to request depreciation recovery of terminal net salvage[120] for its power plants, so the net salvage percentages at issue are only for interim net salvage.[121] AmerenUE's depreciation witness, John Wiedmayer, testified that the historical net salvage indication for Account 312, Boiler Plant Equipment is negative 25 percent. He adjusted his net salvage estimate to 15 percent on the assumption that 60 percent of the retirements are interim retirements, based on an estimated interim survivor curve.[122] Presumably, the other 40 percent of retirements would be terminal, when the power plant is finally retired.

29. MIEC's depreciation witness, James Selecky, recommended the net salvage ratio for this account be reduced from negative 15 percent to negative 10 percent.[123] Selecky recommends this reduction because of his contention that AmerenUE's current interim net salvage depreciation rates have allowed the company to collect more depreciation from customers than the depreciation expenses the company has actually experienced.[124] To avoid what he describes as an over collection, Selecky calculated the average amount of depreciation expense AmerenUE has experienced over the last five and ten years, adjusted that average for inflation to derive an annual amount AmerenUE could expect to recover over the next thirty years, and reduced the net salvage ratio to allow AmerenUE to recover only that amount.

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[119] Wiedmayer Rebuttal, Ex. 105, Page 60, Lines 5-9.

[120] Terminal net salvage relates to decommissioning and dismantlement costs associated with the final retirement of power plants.

[121] Wiedmayer, Rebuttal, Ex. 105, Page 47, Lines 16-19.

[122] Wiedmayer Rebuttal, Ex. 105, Page 47, Lines 19-23.

[123] Selecky Direct, Ex. 404 NP, Page 23, Lines 7-12.

[124] Selecky Direct, Ex. 404 NP, Page 24, Lines 1-7.

Specific Findings of Fact:

30 Selecky's reliance on recent historical levels of interim net salvage expense to set future rates is misplaced. As Wiedmayer explains in his rebuttal testimony:

> net salvage percents are likely to increase as plants age due to the increasing average age of retirements. As the average age of retirements increase, the price level change from the year of initial construction to the year the asset is retired becomes more pronounced and this has an impact on the historical net salvage percents due to the effect of inflation.[125]

For example, a valve that is on the company's books at a cost of $100 when it was installed in 1960, might have cost $125 to remove if it had been replaced in 1990. Because of inflation, to remove the same $100 valve in 2010, might cost $150. To remove it in 2020 might cost $175. Thus, for each year that passes, the ratio of cost of removal to the cost of the valve will increase. For that reason, net salvage estimates need to consider what is likely to occur in the future and properly reflect that information in the estimates.

31. Selecky's proposed reduction to the net salvage ratio simply looks at recent historical depreciation expenses and inflates those number by a constant three percent per year.[126] This arbitrary approach contrasts with Wiedmayer's considered analysis to arrive at a conservative net salvage ratio of 15 percent. In fact, that analysis revealed that a three-year moving average of net salvage percents is above negative 30 percent for every three-year period since 1998.[127]

32. Selecky's only response to Wiedmayer's detailed analysis was to criticize Wiedmayer's decision to reduce his net salvage estimate from negative 25 percent to negative 15 percent based on an assumption that 60 percent of the retirements will be

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[125] Wiedmayer Rebuttal, Ex. 105, Page 48, Lines 8-12.

[126] Selecky Direct, Ex. 404 NP, Schedule JTS-6.

[127] Wiedmayer Rebuttal, Ex. 105, Page 48. Lines 14-19.

interim retirements, meaning that the remaining 40 percent would be final retirements. Selecky points out that elsewhere in his testimony, Wiedmayer states that when the four coal plants currently in service retire nearly 50 to 80 percent of the retirements will be final retirements. Selecky implies that this supposed inconsistency makes Wiedmayer's study unreliable and justifies his simpler approach based on recent historical expenses.[128]

33. The supposedly inconsistent statement is in Wiedmayer's rebuttal testimony. When discussing the general mix of interim and final retirements and the difference between life span and mass property analysis, Wiedmayer said "a substantial portion, nearly 50 to 80 percent, of the retirements associated with life span property will occur on one date in the future when the plant is retired."[129] Wiedmayer's general statement applied to all of the numerous plant accounts for which the company used a life span approach to calculate depreciation rates. For Account 312, the account at issue, the actual data shows that 65 percent of the investment in that account will be retired by interim retirement.[130] Thus, a closer look at the supposed inconsistency in Wiedmayer study indicates there is no inconsistency.

34. The Commission finds that AmerenUE's use of a negative 15 percent net salvage ratio is well supported by the company's data on interim retirements. The Commission also finds that MIEC's proposed adjustment is not supported by the evidence. MIEC's proposed adjustment to require the use of a negative 10 percent net salvage ratio is rejected.

Conclusions of Law:

There are no additional conclusions of law for this issue.

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[128] Selecky Surrebuttal, Ex. 406, Pages 1-15, Lines 11-24, 1-10.

[129] Wiedmayer Rebuttal, Ex. 105, Page 20, Lines 3-5.

[130] Wiedmayer Direct, Ex. 104, Schedule JFW-E1, Page A-5.

Decision:

AmerenUE's use of a negative 15 percent net salvage ratio for Account 312 Boiler Equipment is appropriate. The adjustment to a negative 10 percent net salvage ratio proposed by MIEC is rejected.

d. Inclusion of Retired Steam Generators in Depreciation Analysis for the Callaway Nuclear Plant

Findings of Fact:

Introduction:

35. James Selecky, the witness for MIEC, proposed certain adjustments to AmerenUE's depreciation rates for the Callaway nuclear plant. Those adjustments are predicated on Selecky's adjustment to remove from the plant's retirement history a retirement of four steam generators in 2005.[131] Excluding this particular retirement from the plant's retirement history reduces the interim retirement activity, thereby increasing the average remaining life from 29.8 years to 32.6 years, and decreases the net salvage ratio from a negative 10 percent to a negative 1.2 percent.[132] These changes would reduce AmerenUE's depreciation expense by approximately $5 million.[133] Both AmerenUE and Staff oppose Selecky's proposed adjustment.

Specific Findings of Fact:

36. In 2005, AmerenUE replaced the four, twenty-year old, steam generators at Callaway. Selecky contends the retirement of the steam generators should not be considered as part of the Callaway plant's retirement history because this retirement is not

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[131] Selecky Direct, Ex. 404 NP, Page 18, Lines 5-6.

[132] Selecky Direct, Ex. 404 NP, Page 19, Lines 7-8.

[133] Selecky Rebuttal, Ex. 405, Page 8, Lines 1-8.

typical and dominates the retirement history. This single retirement represents approximately 46 percent of the total retirement in this account from 1986 through 2008. The net salvage expense associated with this retirement is approximately 80 percent of the total net salvage expense this account has incurred since 1986.[134]

37. While this single retirement is substantial compared to retirements that have occurred early in the life of the plant, AmerenUE plans further significant major component replacement projects in the next five years. The retirements associated with those projects will total approximately $48 million.[135] Once these retirements occur, the dollars associated with the steam generator replacements will not be extraordinary in relation to the dollars retired in the future.[136]

38. Also, it is not surprising that equipment retirement has been relatively rare early in the life of the plant. However, interim retirements of equipment will increase as the plant ages, meaning that if actual retirement experience from when the plant is young is excluded from the calculation, the calculation will not be representative of the retirement to be expected in the future when the plant is older.[137]

39. The retirement of the steam generators was also unusual in that while the expected design life of the steam generators was 40 years, the steam generators were only

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[134] Selecky Direct, Ex. 404 NP, Page 18, Lines 8-12.

[135] Wiedmayer Rebuttal, Ex. 105, Page 39, Lines 12-14.

[136] Wiedmayer Rebuttal, Ex. 105, Page 39, Lines 6-9.

[137] Wiedmayer Rebuttal, Ex. 105, Page 41, lines 16-20.

approximately 20-years old at the time of replacement.[138] That means their actual life was only half of what was expected.[139]

40. The shortened life of the generators was due to problems with deteriorating tubes.[140] Because of the problems with the generators, AmerenUE asserted a claim against the manufacturer that resulted in a settlement whereby Westinghouse paid AmerenUE $10 million in cash. AmerenUE also received a fuel credit of $20 million and a non-fuel related credit of $5 million.[141]

41. Selecky asserts that the payments from Westinghouse are a further indication that the premature retirement of the steam generators is abnormal and should be excluded from the company's retirement history.[142] Indeed, Staff's witness agreed that retirements should be removed from the life analysis if they are found to be reimbursed retirements from insurance proceeds or third party payments.[143] However, the payments AmerenUE received from Westinghouse do not make this a reimbursed retirement because none of the payments were booked against accumulated depreciation.[144]

42. The weakness of Selecky's position is demonstrated by the very low net salvage ratio that he calculates. Selecky proposes a net salvage ratio of just negative 1.2

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[138] Wiedmayer Rebuttal, Ex. 105, Page 37, Lines 14-16.

[139] Selecky Rebuttal, Ex. 405, Page 6, Lines 13-16.

[140] Wiedmayer Rebuttal, Ex. 105, Page 38, Line 16.

[141] Selecky Rebuttal, Ex. 405, Page 6, Lines 17-20. The settlement agreement between Westinghouse and AmerenUE is Ex. 438 HC.

[142] Selecky Rebuttal, Ex. 405, Page 6, Lines 9-12.

[143] Rice Rebuttal, Ex. 216, Page 4, Lines 14-16.

[144] Transcript, Page 1421, Lines 7-12. Ex. 169 describes how AmerenUE accounted for the payment received from Westinghouse.

percent.[145] Using that ratio would allow AmerenUE to accumulated only $8.9 million for net salvage for Account 322 over the next 36 years of the life of the Callaway plant. The company has already incurred $32 million in net salvage in that account over the first 24 years of operation. That means Selecky's net salvage estimate would not allow AmerenUE to recover the amount it has already spent on removal costs, let alone the additional costs it will surely incur over the remaining life of the plant.[146]

43. The most important fact is that the steam generators have in fact been retired. That retirement occurred sooner than AmerenUE expected, but it is a part of the plant's retirement history and is not so unusual that it should be ignored. In fact, most nuclear plants have experienced problems with their steam generators and most have replaced or are planning to replace their steam generators.[147] The Commission will reject Selecky's proposed adjustments predicated on the exclusion of the steam generator retirement from the Callaway plant's retirement history.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission rejects Selecky's adjustments to the proposed depreciation rates for the Callaway nuclear plant and accepts the depreciation rates proposed by AmerenUE and Staff.

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[145] Selecky Direct, Ex. 404 NP, Schedule JTS-4.

[146] Wiedmayer Surrebuttal, Ex. 106, Pages 12-13, 16-26, 1-16.

[147] Wiedmayer Rebuttal, Ex. 105, Page 38, Lines 4-7.

e. Transmission and Distribution Plant Depreciation

Findings of Fact:

Introduction:

44. AmerenUE's transmission and distribution accounts include items such as poles and fixtures, overhead conductors and devices, and line transformers.[148] In other words, the equipment used to transmit and distribute electric power to the company's customers. MIEC's witness, James Selecky, asserts that AmerenUE is accruing too much net salvage expense in these accounts and would establish an accrual offset of $25 million to reduce the depreciation expense the company recognizes for these accounts.[149] Staff and AmerenUE oppose Selecky's proposal to establish an accrual offset.

Specific Findings of Fact:

45. The depreciation studies submitted by AmerenUE and Staff both calculated net salvage for these accounts using the accrual method that allows a utility to recover future net salvage over the life of plant through the use of current depreciation rates.[150] The Commission upheld the use of the accrual method in a 2005 decision involving Laclede Gas Company.[151] Subsequently, the Commission upheld AmerenUE's use of the accrual method in AmerenUE's 2007 rate case.[152]

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[148] A list of the accounts included in Transmission and Distribution Plant may be found at Selecky Direct, Ex. 404 NP, Schedule JTS-8.

[149] Selecky Surrebuttal, Ex. 406, Page 16, Lines 1-7.

[150] Wiedmayer Rebuttal, Ex. 105, Page 49, Lines 15-18.

[151] *In the Matter of Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules*, Third Report and Order, 13 Mo. P.S.C. 3d 215 (2005).

[152] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area*, Report and Order, Case No. ER-2007-0002, May 22, 2007, Page 92

46. Selecky does not oppose the continued use of the accrual method, but he contends AmerenUE is accruing what he describes as excessive amounts of net salvage expense that greatly exceed the level of net salvage expense the company actually incurs.[153] Indeed, AmerenUE's average actual annual net salvage expense over the last five years is $15.1 million and over the last ten years, that average expense has been $11.8 million.[154] Selecky contrasts those actual expenses with the $55 million annual net salvage expense AmerenUE will accrue under the depreciation studies prepared by Staff and AmerenUE. Over the years, AmerenUE has accrued approximately $582 million for future net salvage. This amount "seems excessive" to Selecky and he proposes a $25 million offset to reduce that accrual.[155]

47. The amount of Selecky's proposed offset is arbitrary. In his direct testimony, he proposed a $35 million offset,[156] based on his calculation showing that AmerenUE's proposed depreciation expense would include $76.1 million for annual net salvage.[157] After acknowledging a calculation error in his direct testimony, Selecky agreed that AmerenUE's proposed depreciation expense would be only $55 million, a reduction of $21 million.[158] However, he reduced his recommended offset by only $10 million, to $25 million.[159] In fact,

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[153] Selecky Direct, Ex 404 NP, Page 25, Lines 21-23.
[154] Selecky Direct, Ex. 404 NP, Page 27, Lines 8-11.
[155] Selecky Surrebuttal, Ex. 406, Page 16, Lines 12-23.
[156] Selecky Direct, Ex. 404 NP, Page 31, Lines 8-9.
[157] Selecky Direct, Ex. 404 NP, Page 27, Lines 7-8.
[158] Selecky Surrebuttal, Ex. 406, Page 15, Lines 18-22.
[159] Selecky Surrebuttal, Ex. 406, Page 16, Lines 8-18.

Selecky acknowledged the arbitrariness of the amount of his proposed offset when he described it as just a number that he ran up the flagpole.[160]

48. Although Selecky says he is not opposing the use of accrual accounting to calculate net salvage costs, his claim that an offset is needed is firmly based in the discredited method of expensing those costs that the Commission rejected in the *Laclede* decision.[161] His claim that AmerenUE is accruing too much net salvage expense makes sense only if it is accepted that the company's net salvage collections should be limited to something approaching its actual current expenses. As the Commission has held on numerous occasions, expensing is not a reasonable way to calculate net salvage costs and would ensure that the company would under-recover its net salvage costs to the detriment of future generations of ratepayers who would have to pay a disproportionate share of unrecovered net salvage costs when the plant is actually retired.

49. The fact that AmerenUE is currently accruing more than its actual net salvage expense is reasonable and necessary because the transmission and distribution systems are continuously growing and because inflation will make future removal costs more expensive that the cost to remove plant in the past.[162] The size of AmerenUE's system has nearly doubled in the last 50 years and the total distribution plant investment has increased by a factor of sixteen.[163] Current net salvage accruals are larger than current net salvage costs because AmerenUE is accruing dollars for a larger system than the system that

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[160] Transcript, Page 1516, Lines 12-24.

[161] *In the Matter of Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules*, Third Report and Order, 13 Mo. P.S.C. 3d 215 (2005).

[162] Wiedmayer Rebuttal, Ex. 105, Page 69, Lines 9-12.

[163] Wiedmayer Rebuttal, Ex. 105, Page 69, Lines 16-18.

existed 40 or 50 years ago when the property currently being retired was added to the system. In addition, current accruals are for future net salvage costs and those future costs will be higher than current expenses due to the effect of inflation.[164] In fact, the theoretical reserve amount related to net salvage for transmission and distribution is $720 million, and the company has thus far accrued only $582 million for that purpose. Thus, far from over-accruing for net salvage, the company is behind in its recovery of net salvage.[165]

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Selecky's proposed allocation offset of $25 million is arbitrary, is based on a expensing method the Commission has previously rejected, and is unnecessary and inappropriate. That proposed allocation offset is rejected and the net salvage rates proposed by AmerenUE for its Transmission and Distribution accounts are accepted.

3. Coal-Fired Plant Maintenance Expense

Findings of Fact:

Introduction:

1. AmerenUE spends a large sum of money each year to maintain its coal-fired electric generating fleet. During the test year, the twelve months ending March 31, 2009, the company spent $118,967,000 for that purpose.[166] Part of that maintenance expense is incurred for routine maintenance on the power plants, and part is associated with major

[164] Wiedmayer Surrebuttal, Ex. 106, Page 19, Lines 4-13.

[165] Wiedmayer Surrebuttal, Ex. 106, Page 20, Lines 1-12.

[166] Meyer Direct, Ex. 400, Page 4, Chart at Line 9.

overhauls of the production plant that occur during scheduled outages.[167] AmerenUE contends future maintenance expenses will be at or near that test-year level and would use that amount to establish rates in this case.[168]

2. Staff notes that the test-year maintenance expense was substantially higher than the expense for previous years, and, for that reason, proposes to normalize the test-year expense by averaging AmerenUE's maintenance expense over the last three years and using that amount to set rates.[169] Specifically, Staff averaged AmerenUE's non-labor maintenance costs for the 36 months ending at the true-up date, January 31, 2010, and subtracted that amount from the non-labor portion of AmerenUE's test-year maintenance expense, to arrive at a negative adjustment in the amount of $14,939,835.[170] Thus, Staff would subtract $14,939,835 from the test-year expense of $118,967,000, to arrive at an expense level of $104,027,165.

3. MIEC's witness, Greg Meyer, also proposed to normalize AmerenUE's maintenance expense, but he used a more complex method than that proposed by Staff. For each of AmerenUE's four coal-fired production plants Meyer calculated a base level of maintenance expense. That is, a level of maintenance expense that will be incurred each year regardless of whether that power plant undergoes the extra maintenance associated with a scheduled outage. As a second step, Meyer calculated the amount of expense associated with a scheduled outage at each power plant. He then averaged those scheduled outage expenses based on the anticipated number of years between scheduled outages to derive

[167] Transcript, Page 1075, Lines 11-21.

[168] Birk Rebuttal, Ex. 103, Page 17, Lines 3-8.

[169] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Page 93, Lines 6-14.

[170] Grissum True-Up, Ex. 242, Page 2, Lines 1-11.

an estimate of the annual expense associated with scheduled outages. He added the base level of maintenance expense to the annual expense associated with scheduled outages to arrive at a total annual steam production maintenance expense of $104.6 million.[171] Meyer then rounded that number up and recommended $105 million as a normalized level of expense for purposes of establishing rates.

Specific Findings of Fact:

4. Undeniably, AmerenUE's test-year coal plant maintenance expenses of $119 million were significantly higher than they had been in previous years. In the 12 months ending March 31, 2006, those expenses totaled $88.9 million, for the same period ending March 31, 2007, they totaled $93.4 million, and for the twelve-month period ending March 31, 2008, they totaled $91 million.[172] Furthermore, the level of expenses can vary from year to year depending upon how many scheduled outages are planned for that year. That situation requires the Commission to consider whether the test year expense is truly representative of the level of expense the company is likely to experience while the rates established in this case are in effect.

5. AmerenUE offered two reasons why the test-year level of expense is representative of future expense levels. First, in 2003, AmerenUE decided to approximately double the length of scheduled maintenance outage cycles for its coal-fired power plants. As a consequence, AmerenUE undertook fewer scheduled maintenance outages for those plants in the years immediately following 2003. The scheduled outages that would have been undertaken in those years were instead pushed back into later years, with the

[171] Meyer Surrebuttal, Ex. 402 NP, Pages 4-7.

[172] Meyer Direct, Ex. 400, Page 4, Chart at Line 9.

attendant costs also being pushed back.[173] A calculation of actual scheduled outages during the periods of 2001 – 2004 and 2005-2008, and planned outages for 2010 and 2011, was received in camera during the hearing.[174] Those numbers are considered highly confidential so they will not be stated in this order, but they confirm that the number of scheduled outages decreased during the period 2005 to 2008, and that the number of scheduled outages in 2010 and 2011 was expected to return to the level seen in 2001 to 2004.

6. Second, AmerenUE contends the test-year level of expense is representative of future expense levels because of the effects of the global financial crises of 2009. AmerenUE was concerned that it would not be able to obtain the financing needed to perform the maintenance work associated with scheduled outages, and therefore deferred the scheduled outages planned for 2009 into 2010.[175] That deferral has the effect of increasing the level of scheduled outage expense AmerenUE will incur in the future.

7. The Commission traditionally determines a representative future level of expense by looking at numbers in a historic test year. The goal is to establish rates that will give a utility a reasonable opportunity to recover its prudent costs during the period when the rates are in effect. The presumption is that test year expenses will be the best measure of future expenses. However, that presumption is not always correct and it may be appropriate to normalize certain expenses if it appears that a normalized level of expense will be more representative of future expenses.

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[173] Birk Rebuttal, Ex. 103, Page 14, Lines 1-23.

[174] Transcript, Pages 1132-1133, Lines 11-25, 1-9. *See also*, Ex. 162 HC.

[175] Transcript, Page 1049, Lines 6-16.

8. It is, however, inappropriate to blindly "normalize" a test year expense by calculating an average expense from years of lower expense without considering whether the resulting expense level is truly representative of likely future costs. Yet, Staff never looked at the history of scheduled outages to consider whether the period it used to normalize maintenance expense was likely to be representative of future expenses.[176] In fact, Staff's witness testified she ignored everything except the historical numbers.[177] Therefore, Staff's purported normalization is unreliable.

9. MIEC's proposed normalization is more carefully thought out to give appropriate consideration to whether the normalized expense level will be representative of future costs. It does that by taking into account the scheduled outages for each of the power plants and recognizing the effect those scheduled outages will have on the expenses the company will incur.

10. AmerenUE criticizes MIEC's proposed normalization on two bases. First, it contends MIEC's normalization uses expenses from five or six years ago that have not been adjusted to recognize the effect of inflation.[178] However, the Commission finds that MIEC's numbers do not have to be adjusted for inflation because the base line for maintenance expense, excluding scheduled outage expense, remained essentially flat between 2005 and 2007, indicating that despite inflation, other techniques, technologies, or cost of materials have decreased enough to offset the cost of inflation.[179]

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[176] Transcript, Page 1190, Lines 8-16.

[177] Transcript, Page 1212, Lines 9-21.

[178] Birk Supplemental Testimony, Ex. 158, Page 3, Lines 17-19.

[179] Transcript, Pages 1144-1145, Lines 9-25, 1-19.

11. AmerenUE's second criticism of MIEC's normalization is that it fails to take into account the reduced number of scheduled outages that occurred during the period it used to normalize the maintenance expenses. That criticism is valid, but can be avoided if Meyer's normalization technique is applied to the actual outages planned for the period when the rates established in this case will be in effect.

12. AmerenUE anticipates filing its next rate case sometime before the end of 2010, meaning the rates established in this case will likely remain in effect for only about 18 months.[180] During an in camera cross examination of Mr. Birk, MIEC elicited testimony that took Meyer's estimation of a base level of annual maintenance expense and added his estimation of the expense associated with each scheduled outage AmerenUE plans to undertake in 2010.[181] That calculation resulted in an estimated expense for 2010 of $110.2 million.[182]

13. MIEC offered that number to show that Meyer's normalization method would result in an estimate relatively close to the amount AmerenUE has budgeted for maintenance expense in 2010. However, using that number, which is based on the scheduled outages actually planned for 2010, as the basis for establishing rates also eliminates AmerenUE's criticism that the normalization fails to take into account the increasing number of scheduled outages that will occur while the rates established in this case are in effect. Therefore, the Commission finds that $110.2 million is a reasonable normalization of AmerenUE's coal-plant maintenance expense.

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[180] Transcript, Page 1098, Lines 7-12.

[181] Transcript, Pages 1009-1013. See also Ex. 443.

[182] Ex. 443 HC.

Conclusions of Law:

A. In a 1984 case addressing a Commission rate case decision, the Missouri Court of Appeals described the concept of normalization of a test-year expense as follows:

> The test year is a period past, but is employed as a vehicle upon which to project experience in a future period when the rates determined in the case will be in effect. Normalization of a test year cost by multi-year averaging of the cost based on experience assumes that the cost rises and falls, with the consequence that the actual cost incurred in the test year is not representative.[183]

That means that in normalizing a test year expense, the Commission is attempting to establish rates that will allow the utility a reasonable opportunity to recover its anticipated expenses. For that reason, the Commission must consider whether a proposed normalized test year expense is reasonably related to anticipated future expenses.

Decision:

The Commission concludes that $110.2 million is a reasonable normalization of AmerenUE's annual coal-plant maintenance expense.

4. Nuclear Fuel Expense

Findings of Fact:

Introduction:

1. AmerenUE's Callaway nuclear plant is refueled every 18 months. During each refueling, about half of the uranium fuel assemblies in the reactor core are removed and replaced with new assemblies.[184] AmerenUE refueled the Callaway plant beginning in April

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[183] *State ex rel. Missouri Power and Light Co. v. Public Service Com'n*, 669 S.W.2d 941, 945, (Mo App. W.D. 1984).

[184] Irwin Rebuttal, Ex. 127, Page 3, Lines 13-15.

2010, with fuel assemblies purchased and delivered to the plant before January 31, 2010.[185]

2. AmerenUE would include the increased cost of the fuel assemblies installed during the April 2010 refueling in the average nuclear fuel cost to be recovered in base rates resulting from this case.[186] Staff, supported by MIEC, would base AmerenUE's nuclear fuel cost on its average cost for fuel actually burned during the fifteen-month period beginning October 2008 and continuing through January 31, 2010, the true-up cut off date established for this case.[187] Under Staff and MIEC's proposal, AmerenUE would not be allowed to recover the increased cost of the nuclear fuel loaded into the Callaway plant in April 2010. The difference between the proposals amounts to approximately $11 million.[188]

Specific Findings of Fact:

3. The facts surrounding this issue are not in dispute. AmerenUE has bought and paid for nuclear fuel assemblies to refuel the Callaway nuclear power plant beginning in April 2010. Those assemblies are highly engineered and specifically designed for use at Callaway.[189] The Callaway plant must be shut down to be refueled and a shut-down is costly, so AmerenUE must purchase those fuel assemblies and have them available on-site well in advance of the shut-down.[190]

4. The nuclear fuel assemblies are accounted for as construction work in progress until they are fully assembled; once assembled they are accounted as nuclear fuel assembly

[185] Irwin Rebuttal, Ex. 127, Page 4, Lines 2-5.
[186] Finnell Direct, Ex. 130, Page 9, Lines 5-7.
[187] Grissum Surrebuttal, Ex. 224, Page 2, Lines 9-12. See also, Transcript, Page 2657, Lines 6-14.
[188] Revised True-Up Reconciliation, Ex. 242.
[189] Irwin Rebuttal, Ex. 127, Page 4, Lines 20-22.
[190] Transcript, Pages 2665-2666, Lines 21-25, 1-7.

stock. The fuel assemblies were completed and accounted for as stock in October 2009.[191] When burned in the reactor, the assemblies are expensed as fuel expense.[192] During the time after the fuel assemblies are completed, until the time they are loaded and burned in the reactor, the company receives no carrying costs on those fuel assemblies.[193]

5. The nuclear fuel price is based on the amortization of the initial costs of the fuel assemblies. As such, the nuclear fuel price AmerenUE proposes to include in rates in this case has not and will not occur until the new fuel assemblies have been loaded into the Callaway reactor during refueling and the Callaway unit is placed back in-service sometime in June 2010.[194] This will be approximately four months after the January 31, 2010 true-up date.

6. If AmerenUE's increased nuclear fuel costs are not included in base rates, the company will be able to recover those costs through the operation of its fuel-adjustment clause, subject to the 95/5 sharing mechanism included in that fuel adjustment clause.[195] Because of the way the fuel adjustment clause works, AmerenUE would not be able to fully recover its 95 percent share of those increased costs until September 30, 2011.[196]

7. In AmerenUE's last rate case, ER-2008-0318, AmerenUE was allowed to recover the increased cost of nuclear fuel associated with a refueling that occurred approximately

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[191] Transcript, Page 2665, Lines 12-15.
[192] Transcript, Page 2664, Lines 12-20.
[193] Transcript, Page 2665, Lines 16-20.
[194] Grissum Surrebuttal, Ex. 224, Page 3, Lines 17-22.
[195] Transcript, Page 2660, Lines 4-25.
[196] Transcript, Pages 2661-2662, Lines 1-25, 1-7.

one month after the true-up cut off date for that case. No party in that case objected to AmerenUE's recovery of those costs.[197]

Conclusions of Law:

A. The disagreement between the parties concerns the application of the true-up cut-off date. The Commission employs a test-year concept to evaluate a utility's income and expenses for the purpose of setting just and reasonable rates. For this case, the test year was established as the twelve-month period ending March 31, 2009, with an additional true-up period extending through January 31, 2010. That means that for that test-year period, extended through the true-up, the Commission has examined the company's income and expenses to determine the amount of revenue the company should be allowed to generate through the rates to be established as a result of this case. The goal is to match income and expenses over the same period so that a true level of required revenue can be determined.

B. The increased cost of the fuel assemblies loaded into the Callaway reactor during the April shut-down will not begin to be expensed until the reactor is back in operation, and thus will fall outside the test-year and the true-up period. In most situations, the Commission will not allow for out-of-period adjustments because to do so risks upsetting the matching principle. That is, reaching outside the test year to pull in an expense could allow the company to recover excess revenue if that out-of-test-year expense would otherwise have been offset by some unconsidered item of out-of-test-year income.

C. However, the matching principle is not an absolute bar to an appropriate out-of-period adjustment. When faced with this question in the past, the Commission has said

[197] Transcript, Pages 2658-2659, Lines 21-25, 1-6.

"when such known and measurable increases in expenses occur it is more equitable to allow such an expense to be reflected in the revenue requirement than to disallow it for the sole reason that corresponding revenues may be lacking."[198] On that basis, the Commission has, for example, allowed a company to recover for a known postage rate increase that would occur outside the test year,[199] and a known wage increase and FICA withholding tax increase, again outside the test year.[200]

D. In this case, AmerenUE's cost to purchase the fuel assemblies is absolutely known and measurable, and has been known and measurable since October 2009. The fuel assemblies are presumably now in place and will be generating electricity at the time rates resulting from this case go into effect. Ultimately, AmerenUE would recover 95 percent of its increased nuclear fuel costs through operation of its fuel adjustment clause, but it would have to wait many months to fully recover those costs.

E. The matching principle is important, but the ultimate purpose of a test year is to establish rates that will give a utility a reasonable opportunity to recover its prudent costs during the period when the rates are in effect. Allowing AmerenUE to recover its increased fuel costs in its base rates is necessary to allow the company a reasonable opportunity to recover its prudent costs.

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[198] *In the Matter of St. Louis County Water Company, St. Louis, Missouri, for Authority to File Tariffs to Increase Water Service Provided to Customers in the Missouri Service Area of the Company,* Report and Order, 29 Mo. P.S.C. (N.S.) 425, 435 (1988).

[199] *Id.*

[200] *In the Matter of Citizens Electric Corporation of Ste. Genevieve, Missouri, for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company,* Report and Order, 24 Mo. P.S.C. (N.S.) 450, 457 (1981).

Decision:

AmerenUE shall recover its increased nuclear fuel costs associated with the April 2010 refueling of the Callaway nuclear plant as part of its base fuel costs. The adjustments proposed by Staff and MIEC that would deny that recovery are rejected.

5. Vegetation Management and Infrastructure Inspection Expense

Findings of Fact:

Introduction:

1. AmerenUE's vegetation management and infrastructure inspection expense is closely associated with two Commission rules. Following extensive storm related service outages in 2006, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution systems. Those rules, entitled Electrical Corporation Infrastructure Standards[201] and Electrical Corporation Vegetation Management Standards and Reporting Requirements,[202] became effective on June 30, 2008.

2. The rules establish specific standards requiring electric utilities to inspect and replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow a utility the means to recover the extra costs it incurs to comply with the requirements of the rule.

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[201] Commission Rule 4 CSR 240-23.020.

[202] Commission Rule 4 CSR 240-23.030.

3. In ER-2008-0318, the Commission allowed AmerenUE to recover $54.1 million in its base rates for vegetation management costs, and $10.7 million for infrastructure inspection costs. However, since the rules were new, the Commission found that AmerenUE had too little experience to reasonably know how much it would need to spend to comply with the vegetation management and infrastructure inspection rules. Because of that uncertainty, the Commission established a two-way tracking mechanism to allow AmerenUE to track its vegetation management and infrastructure costs.

4. The base level for that tracker was set at $64.8 million ($54.1 million for vegetation management plus $10.7 million for infrastructure inspection). The order required AmerenUE to track actual expenditures around that base level. In any year in which AmerenUE spent below that base level, a regulatory liability would be created. In any year in which AmerenUE's spending exceeded the base level, a regulatory asset would be created. The regulatory assets and liabilities would then be netted against each other and would be considered in AmerenUE's next rate case. The tracking mechanism contained a 10 percent cap so if AmerenUE's expenditures exceeded the base level by more than 10 percent it could not defer those costs under the tracking mechanism, but would need to apply for an additional accounting authority order. The Commission's order indicated that the tracking mechanism would operate until new rates were established in AmerenUE's next rate case.[203]

5. This is, of course, the next rate case, and AmerenUE asks that the tracker be continued. Staff, MIEC, and Public Counsel contend the Commission should eliminate the

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[203] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 48-49.

tracker and establish an allowance for vegetation management and infrastructure inspection expenses based on the company's expenditures during the test year.

Specific Findings of Fact:

6. The Commission must resolve two issues regarding these vegetation management and infrastructure expenses. First, the Commission must decide whether the existing tracker should be continued.

7. The Commission approved a tracker in the last rate case because the vegetation management and infrastructure rules were still very new. As a result, no one knew with any certainty how much AmerenUE would need to spend to comply with the rules' provisions.[204] AmerenUE has now been operating under those rules for two years. Although the rule went into effect on June 30, 2008, AmerenUE began complying with the requirements of the rules on January 1, 2008.[205]

8. Staff and MIEC contend that experience is sufficient to allow the Commission to confidently set AmerenUE's rates without renewing the tracker. However, the new rules impose substantial new requirements for tree trimming[206] and infrastructure inspections. AmerenUE has not yet completed a full four/six year vegetation management cycle on its entire system. Over half of its circuits have not yet been trimmed to the new standards. That is important because every circuit is unique, with different amounts of vegetation that must be trimmed, and requires a different amount of work to meet the standards imposed

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[204] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 41.

[205] Meyer Rebuttal, Ex. 402NP, Page 11, Line 13.

[206] Transcript, Page 1759, Lines 8-13.

by the rules.[207] Therefore, it is still difficult to predict what AmerenUE's normal level of vegetation management expenses will be.[208] The same is true for AmerenUE's efforts to comply with the infrastructure inspection rule.[209]

9. As the Commission said in the last rate case, the tracker serves to protect both the company and its ratepayers during this initial period of uncertainty about the cost to comply with the new rules. If the company spends less than the base level set in the tracker, the excess allowance will be tracked and returned to ratepayers in the next rate case. That is exactly what has happened in this case, and thus, ratepayers have already benefited from the existence of the tracker.

10. AmerenUE's system reliability has improved since the new rules went into effect,[210] and the Commission believes that vegetation management and infrastructure inspection is very important to that improved reliability. The Commission wants to encourage AmerenUE to continue to spend the money needed to improve reliability. Because there is still a great deal of uncertainty about the amount of spending needed to comply with the rules, the Commission finds that the tracker is still needed. That does not mean the tracker will become permanent. AmerenUE's witness suggests the company will have a level of experience needed to better predict costs in two to four years.[211] It may not take that long, and the Commission will certainly revisit this issue in AmerenUE's next rate case, but for this case, the Commission will renew the existing vegetation management and infrastructure inspection tracker.

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[207] Wakeman Rebuttal, Ex. 109, Page 8, Lines 7-8.

[208] Wakeman Rebuttal, Ex. 109, Page 7, Lines 1-23.

[209] Wakeman Rebuttal, Ex. 109, Pages 8-9, Lines 16-23, 1-11.

[210] Zdellar Direct, Ex. 157, Pages 3-15.

[211] Wakeman Rebuttal, Ex. 109, Page 7, Lines 20-21.

11. Having renewed the tracker, the Commission must decide the dollar amount to be included as a base level for that tracker. AmerenUE spent $50.4 million on vegetation management in the twelve-month period ending at the true-up date, January 31, 2010.[212] For the same period, AmerenUE spent $7.6 million on infrastructure inspection expenses.[213] That is a total of $58 million. The non-AmerenUE parties would use those actual expenditures to establish AmerenUE's rates for this case.

12. AmerenUE contends its forecasted expenditures for 2010 and 2011 should be used to set its new rates. The average forecasted expenditures for those two years are $53.7 million for vegetation management and $8.9 million for infrastructure inspections, for a total of $62.6 million.[214] AmerenUE would use that amount as the base level for a renewed two-way tracker.

13. In general, the Commission prefers to use historical information rather than forecasts to establish rates. In the last rate case, the Commission used the company's forecasted budget amounts to set the base level of the tracker. It did so because at that time there was very little historical information upon which to base its decision. More information is available now and while there is still enough uncertainty to justify the continuation of the tracker, the additional historical information is sufficient to set a reasonable base level for that tracker. Therefore, the Commission will set the base level of the tracker at $58 million,

14. One other matter remains to be resolved. Through February 28, 2010, AmerenUE has collected approximately $5 million more than it actually incurred to comply with the

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[212] Meyer Rebuttal, Ex. 402NP, Page 10, Lines 7-10.

[213] Meyer Rebuttal, Ex. 402NP, Page 14, Lines 1-5.

[214] Wakeman Rebuttal, Ex. 109, Page 10, Lines 14-20.

Commission's vegetation management and infrastructure inspection rules.[215] Staff proposed to reduce that over-collection by $2 million, which is the amount the company incurred from October 1, 2008 through February 28, 2009, in excess of the amount included in rates.[216] That would indicate a remaining over-collection of $3 million, but Staff updated that number at the end of the hearing to $3.4 million.[217]

15. Staff recommends that the $3.4 million remain in the tracker as an addition or offset to any future amounts deferred. The Commission would then address ultimate disposition of any amounts deferred in the next rate case.[218] AmerenUE did not offer a proposal on how the $3.4 million over-collection should be returned to its customers until its initial brief. At that time, the company recommended that the over-collection be returned to customers, amortized over three years.[219]

16. Staff's proposal would potentially offset an increase in AmerenUE's expenses for the next rate case and thereby decrease any rate increase that would result from that future case. AmerenUE's proposal has the advantage of decreasing the rate increase that will result from this decision. The Commission will accept AmerenUE's proposal and directs that the $3.4 million over collection be returned to customers, amortized over three years.

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[215] Rackers Surrebuttal, Ex. 203, Page 4, Lines 11-12.

[216] Rackers Surrebuttal, Ex. 203, Page 4, Lines 19-21. In ER-2008-0318, the Commission allowed AmerenUE to accumulate and defer those expenses in an Accounting Authority Order for consideration in this rate case.

[217] Exhibit 240.

[218] Rackers Surrebuttal, Ex 203, Page 5, Lines 4-9.

[219] Post-Hearing Brief of AmerenUE, Pages 119-120.

Conclusions of Law:

A. Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including AmerenUE, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

B. Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates … .

C. Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including AmerenUE, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that would allow AmerenUE to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[220]

Decision:

AmerenUE shall establish a tracking mechanism to track future vegetation management and infrastructure costs. That tracking mechanism shall include a base level of $58 million ($50.4 million + $7.6 million = $58 million). Actual expenditures shall be tracked around that base level with the creation of a regulatory liability in any year where AmerenUE spends less than the base amount and a regulatory asset in any year where AmerenUE spends more than the base amount. The assets and liabilities shall be netted against each other and shall be considered in AmerenUE's next rate case. The tracking mechanism shall contain a ten percent cap so expenditures exceeding the base level by more than ten percent shall not be deferred under the tracking mechanism. If AmerenUE's vegetation management and infrastructure inspection costs exceed the ten percent cap, it may request additional accounting authority from the Commission in a separate proceeding. The tracking mechanism shall operate until new rates are established in AmerenUE's next rate case.

The $3.4 million AmerenUE over-collected from its ratepayers under its previous tracking mechanism shall be returned to its ratepayers, amortized over three years.

6. Storm Restoration

Findings of Fact:

Introduction:

1. AmerenUE must spend money each year to restore electric service after its electric system suffers damage as the result of storms. Each year some of that damage results

[220] Commission Rule 4 CSR 240-23.030(10).

from normal, routine storms. But occasionally, the electric system is struck by a truly extraordinary storm that can greatly increase restoration costs.

2. The Commission has generally allowed an electric utility to recover the Operations and Maintenance (O&M), excluding internal labor, costs to restore service after normal storms by including an amount in the cost of service based on some multiyear average level.[221] For the costs to restore service after an extraordinary storm, the Commission has usually allowed the utility to accumulate and defer those costs through an accounting authority order, an AAO.[222] The accumulated and deferred costs are then considered in the utility's next rate case. Generally, the Commission allows the utility to recover those costs amortized over a five-year period.[223]

3. Staff would use that same procedure in this case. Staff proposes to use a four-year average of AmerenUE's normal O&M, non-labor related, storm restoration costs to allow $6.4 million in AmerenUE's cost of service for normal storm restoration costs. AmerenUE's actual storm restoration cost during the test year totaled $10.4 million. Staff would remove $4 million from that amount as related to extraordinary storms, and allow AmerenUE to recover that $4 million amortized over five years.[224] MIEC's witness, Greg Meyer advocates the same approach, although he would allow only $5.2 million in AmerenUE's

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[221] A utility may also incur substantial capital investment costs to replace things like power poles after a storm. Those investment costs are added to the company's rate base and recovered in that manner. This issue does not concern those capital costs.

[222] Rackers Rebuttal, Ex. 202, Page 2, Lines 21-24.

[223] Rackers Rebuttal, Ex. 202, Page 2, Lines 5-11.

[224] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Pages 89-90, Lines 25-29, 1-16.

cost of service, as that was the amount allowed in the company's previous rate case, ER-2008-0318.[225]

4. AmerenUE proposes to use a new approach to the recovery of storm restoration expenses. It would have the Commission set the base level of storm restoration O&M costs at the actual amount incurred during the test year, which is $10.4 million. AmerenUE then proposes that the Commission establish a tracking mechanism to track actual expenses against that base level. If AmerenUE spent less than the base level, the difference could be returned to rate payers in the next rate case. If expenses exceeded the base level, AmerenUE could seek to recover the difference in its next rate case.[226]

Specific Findings of Fact:

5. The O&M non-labor cost AmerenUE incurs can vary greatly from year to year depending upon whether the electric system is struck by a major storm. For 2004 and 2005, those costs were only $1 million and $2 million respectively. For 2006 and 2007, the costs jumped to $26 million and $33 million. For 2008 and 2009, they fell again to $4 million and $9 million.[227] Under the approach the Commission has used in past cases, the company may under recover in years when costs are high, but may over recover in years when costs are low. If the company incurs truly extraordinary storm restoration costs in a particular year, it is able to recover those costs through the accounting authority mechanism. In this case, AmerenUE is recovering amortized storm restoration costs from five different storm events.[228]

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[225] Meyer Direct, Ex. 400, Pages 27-28, Lines 17-23, 1-2.

[226] Zdellar Direct, Ex. 157, Page 21, Lines 1-12.

[227] Rackers Surrebuttal, Ex. 203, Page 6, Chart at Line 6.

[228] Staff Report – Revenue Requirement/Cost of Service, Ex 200, Pages 90-91.

6. No party disputes that AmerenUE has provided good storm restoration service in recent years, and no one has alleged that any of its storm restoration expenses have been imprudent.

7. The Commission is unwilling to implement another tracker. As the Commission has previously indicated, trackers should be used sparingly because they tend to limit a utility's incentive to prudently manage its costs. If all such costs can simply be passed on to ratepayers, there is a natural incentive for the company to simply incur the cost. If the company must consider whether it will be able to recover a cost, it is more likely to think before it spends and maximize any possible cost savings.

8. The storm cost recovery method the Commission has used in the past has worked reasonably well. The company will ultimately recover its extraordinary costs resulting from unpredictable extraordinary storms through the accounting authority order mechanism, but the company still has a strong incentive to minimize its costs. Staff's proposal to include the four-year average of $6.4 million for storm restoration costs, while amortizing the extra $4 million in test year expense over five years is reasonable. MIEC's alternative proposal to include only $5.2 million in the company's cost of service is based only on the amount allowed in the last rate case. As such it is arbitrary and unsupported by any evidence offered in this case.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

AmerenUE's request to establish a tracking mechanism is denied. AmerenUE shall include $6.4 million in its cost of service for storm restoration costs. The remaining $4 million in test year storm restoration expense shall be amortized and recovered over five years.

7. Union Issues

Findings of Fact:

Introduction:

1. The various unions that represent AmerenUE's employees appeared at the hearing to support the company's request for a rate increase. However, they asked the Commission to order AmerenUE to spend more money on employee training and to take specific steps to increase its internal workforce so that it will use fewer outside contractors. AmerenUE contends it is currently providing safe and adequate service and argues the Commission has no authority to manage the day-to-day affairs of the company.

Findings of Fact:

2. Michael Walter is the Business Manager of International Brotherhood of Electrical Workers Local 1439, AFL-CIO.[229] He testified that AmerenUE has not spent enough on training new workers and as a result has over-relied on outside contractors to perform normal and sustained work.[230] In particular, Walter is concerned that AmerenUE's trained work force is aging and he sees a need for increased training of new workers capable of stepping in when the current workforce retires.[231] He asks the Commission to require AmerenUE to spend a portion of its rate increase to improve training and increase the portion of the workload performed by its internal workforce.[232] AmerenUE's witness replied

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[229] Walter Rebuttal, Ex. 650, Page 1, Lines 2-3.

[230] Walter Rebuttal, Ex. 650, Pages 2-7.

[231] Transcript, Page 2575, Lines 18-24.

[232] Walter Rebuttal, Ex.650, Pages 7-9.

that the company must rely on outside contractors to meet some of its normal workforce needs because of a shortage of qualified personnel.[233]

3. In response to those concerns, Commissioners Davis and Jarrett asked the AmerenUE witnesses how the company would spend extra money to training power plant operators if provided additional training funds as a result of this case.[234] In response to Commissioners Davis' and Jarrett's questions, AmerenUE filed an exhibit detailing how it would spend extra money on training. AmerenUE also agreed to assess the incremental value to customers of its additional training investments and to present those findings to Staff and Public Counsel by December 31, 2011.[235] AmerenUE's witness explained that these additional funds would be used to train AmerenUE's distribution employees.[236]

4. The Commission finds that the evidence presented by the union witnesses does not demonstrate that AmerenUE has failed to supply safe and adequate service to the public. Furthermore, for reasons fully explained in its Conclusions of Law, the Commission does not have the authority to dictate the manner in which AmerenUE conducts its business. Therefore, the Commission will not attempt to dictate to the company regarding its use of outside contractors.

5. However, the union witnesses and AmerenUE agree that there is a need for improved training to replace skilled workers nearing retirement age. It takes five to seven

[233] Wakeman Surrebuttal, Ex. 110, Page 10, Lines 5-15.

[234] Transcript, Page 2619, Lines 3-20, and Page 2621, Lines 5-9. The Commission allocated extra money for additional training in AmerenUE's last rate case, ER-2008-0318. AmerenUE explained how that money was spent in the direct testimony of Mark Birk, Ex. 102, Pages 15-16.

[235] Ex. 179.

[236] Transcript, Page 2783, Lines 21-24.

years of training to replace a skilled electrical worker.[237] For several job classifications, many workers are nearing retirement age and will soon be leaving the company.[238] Thus, the Commission finds that there is a need for additional training to attempt to meet that need.

6. Therefore, the Commission will add $1.29 million to AmerenUE's cost of service to fund increased training staff. The Commission will also allow AmerenUE $2.1 million for additional training equipment and materials, to be amortized over five years and recovered in rates. That would increase AmerenUE's cost of service by an additional $420,000 per year, for a total annual increase of $1,710,000.

Conclusions of Law:

A. The Commission has the authority to regulate AmerenUE, including the authority to ensure that the utility provides safe and adequate service. However, the Commission does not have authority to manage the company. In the words of the Missouri Court of Appeals,

> The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.[239]

Therefore, the Commission does not have the authority to dictate to the company whether it must use internal workforce rather than outside contractors to perform the work of the company.

Decision:

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[237] Transcript, Page 2576, Lines 21-25.

[238] Transcript, Page 2593, Lines 4-9.

[239] *State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177, 182 (Mo. App. 1960)

The evidence presented by the union witnesses does not demonstrate that AmerenUE has failed to provide safe and adequate service and the Commission will not dictate to the company whether it must use its internal workforce or outside contractors to perform the company's work. However, the Commission will add $1,290,000 to AmerenUE's cost of service to fund increased training staff. The Commission will also allow AmerenUE $2,100,000 for additional training equipment and materials, to be amortized over five years and recovered in rates. That increases AmerenUE's cost of service by $1,710,000 per year. AmerenUE shall assess the incremental value to customers of these additional investments and provide that assessment to Staff and Public Counsel by December 31, 2011.

8. Fuel Adjustment Clause

Findings of Fact:

Introduction:

1. In AmerenUE's last rate case, ER-2008-0318, the Commission allowed AmerenUE to implement a fuel adjustment clause.[240] The approved fuel adjustment clause includes an incentive mechanism that requires AmerenUE to pass through to its customers 95 percent of any deviation in fuel and purchased power costs from the base level. The other 5 percent of any deviation is retained or absorbed by AmerenUE.[241]

2. In the direct testimony of its witness, Lynn Barnes, AmerenUE proposed that its existing fuel adjustment clause be continued, with a few minor refinements.[242] When it filed

[240] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

[241] *Id.* at Page 76.

[242] Barnes Direct, Ex. 121, Page 3, Lines 2-10.

its direct testimony, Staff agreed that AmerenUE's existing fuel adjustment clause should be continued with the refinements proposed by AmerenUE and some additional modifications proposed by Staff.[243] The minor modifications to the fuel adjustment clause were resolved in the First Stipulation and Agreement that the Commission approved on March 24, 2010. Therefore, the Commission will not further address those modifications.

3. In an order issued on February 17, 2010, after the parties had filed rebuttal testimony, the Commission indicated it wanted to hear more evidence from the parties about the continued appropriateness of the 95 percent pass-through mechanism in AmerenUE's current fuel adjustment clause. To that end, the Commission offered the parties an opportunity to file additional direct, rebuttal, and surrebuttal testimony on an expedited schedule before the start of the hearing.[244]

4. AmerenUE responded by filing extensive additional testimony explaining why the company still needs a fuel adjustment clause that incorporates the current sharing mechanism. MIEC, Public Counsel, and Staff also filed additional testimony regarding the fuel adjustment clause.

5. MIEC refiled the testimony that its witness, Maurice Brubaker, offered regarding the fuel adjustment clause in AmerenUE's last rate case.[245] In that testimony, Brubaker advised the Commission to implement an 80/20 sharing mechanism that would allow the company to pass-through to customers only 80 percent of the changes in fuel cost and off-

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[243] Staff Report – Revenue Requirement/Cost of Service, Ex. 200, Pages 105-111.

[244] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Order Directing the Parties to Submit Testimony Concerning the Appropriateness of AmerenUE's Current Fuel Adjustment Clause, File No. ER-2010-0036, February 17, 2010.

[245] ER-2008-0318.

system sales.[246] Brubaker would, however, cap the impact of the sharing mechanism so that the sharing would have no more than a 50 basis point impact on AmerenUE's return on equity.[247]

6. Public Counsel also offered testimony supporting an 80/20 sharing mechanism. Ryan Kind offered his opinion that such a sharing percentage is necessary to ensure that AmerenUE continues to make its best efforts to minimize fuel costs and maximize its off-system sales margins.[248]

7. Staff filed supplemental testimony explaining that since little time has passed since AmerenUE's fuel adjustment clause went into effect, it has not compiled enough data to meaningfully analyze that fuel adjustment clause. As a result, Staff suggests the Commission leave the current fuel adjustment clause in place without changing the sharing mechanism.[249]

Specific Findings of Fact:

8. In AmerenUE's last rate case, the Commission found that AmerenUE should be allowed to establish a fuel adjustment clause because its fuels costs were substantial, beyond the control of the company's management, and volatile in amount. The Commission also found that AmerenUE needed a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity and to be able to compete for capital with other utilities that have a fuel adjustment clause.[250] In the same rate case, the

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[246] Brubaker Additional Direct – FAC, Ex. 413, Attachment 2, Page 11 of 19.

[247] Brubaker Additional Direct – FAC, Ex. 413, Attachment 2, Page 11 of 19.

[248] Kind Additional Direct – FAC, Ex. 301, Page 2, Lines 3-18.

[249] Mantle Supp. Direct – FAC, Ex. 221, Pages 5-6, Lines 15-23, 1-7.

[250] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009,

Commission found that a 95/5 sharing mechanism would give AmerenUE a sufficient opportunity to earn a fair return on equity, while protecting customers by preserving the company's incentive to be prudent.[251]

9. Nothing has changed in the months since the Commission established AmerenUE's fuel adjustment clause to cause the Commission to change that decision. The Commission finds that AmerenUE's fuel and purchased power costs are clearly substantial, comprising 47 percent of the company's total operations and maintenance expense. Furthermore, the revenue the company receives from off-system sales, which is also tracked through the fuel adjustment clause, is also substantial.[252] These fuel and purchased power costs continue to be dictated by national and international markets, and thus are outside the control of AmerenUE's management.[253] Finally, these costs and revenues continue to be volatile. For example, the price AmerenUE was able to obtain in the market for off-system electricity sales declined by nearly half from 2008 to 2009.[254]

10. Furthermore, the Commission finds that AmerenUE still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. AmerenUE's regulatory lag problems have not improved since its last rate case. In recent years, the company has been unable to earn its allowed rate of return, and in large part, that problem is due to fuel-related issues.[255] Even with the fuel adjustment clause in place, AmerenUE's return on equity for the year ending December 2009, was only 7.27 percent.

Pages 69-70.

[251] *Id*., at Page 76.

[252] Barnes Direct, Ex. 121, Page 7, Lines 17-23.

[253] Barnes Direct, Ex. 121, Page 7, Lines 23-26.

[254] Haro Additional Rebuttal – FAC, Ex. 126, Page 13, Lines 13-19.

[255] Transcript, Page 2409, Lines 5-11.

Without a fuel adjustment clause, that return would have dropped to 6.69 percent, over 400 basis points below the company's authorized return on equity of 10.76 percent.[256] In addition, AmerenUE still must compete in the capital markets with other utilities and the vast majority of those utilities have fuel adjustment clauses.[257]

11. For the forgoing reasons, the Commission finds that AmerenUE should be allowed to continue to operate under a fuel adjustment clause. However, the Commission's chief concern about the existing fuel adjustment clause, and the reason it asked the parties to present additional testimony about this matter, is an uncertainty about the appropriate amount of sharing required to assure that AmerenUE continues to make its best efforts to control its fuel-related costs and to maximize its off-system sales.

12. The majority of electric utilities operate with a fuel adjustment clause that does not have any sort of sharing mechanism.[258] Yet, the Commission is concerned that allowing an uncontrolled pass-through of costs will reduce a utility's incentive to carefully examine and perhaps reduce those costs. In the last rate case, the Commission decided that a 95/5 sharing mechanism was appropriate to allow the company to recover its prudently incurred costs while still protecting ratepayers. But the Commission wanted to know how well that sharing mechanism was working in practice.

13. MIEC and Public Counsel advocated for a revised sharing mechanism that would require AmerenUE to absorb a larger percentage of increasing fuel costs to increase its incentive to properly manage those costs. However, the testimony those parties presented was based on little more than the opinions of their witnesses about an appropriate sharing

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[256] Barnes Additional Direct – FAC, Ex. 122, Page 5, Lines 16-19.

[257] Transcript, Page 2421, Lines 1-6.

[258] Transcript, Page 2421, Lines 7-14.

percentage. No party presented any evidence that would indicate how the 95/5 sharing mechanism is working in practice for this company. Certainly, no evidence was produced to show that AmerenUE had acted imprudently with regard to its procurement of fuel and off system sales since the fuel adjustment clause went into effect in March 2009. On the contrary, the efficiency of AmerenUE's power plant performance as measured by equivalent availability improved in 2009, after the fuel adjustment clause was put into effect.[259]

14. As Staff explained in its testimony, the implementation of AmerenUE's fuel adjustment clause has only just begun. Staff will not complete its first prudence review of AmerenUE's operations under the existing fuel adjustment clause until August 2010.[260] The prudence review is very important to Staff in determining whether the fuel adjustment clause was working in the manner intended, as is seeing whether AmerenUE has changed its practices regarding their purchase and hedging of fuel and regarding off-system sales.[261] Until that review process is complete, Staff concluded it would not have sufficient data to meaningfully analyze the effectiveness of AmerenUE's fuel adjustment clause.[262]

15. Substantially changing the existing fuel adjustment clause without a meaningful analysis could have severe adverse consequences for AmerenUE and ultimately for ratepayers. Gary Rygh, a witness for AmerenUE explained that a significant modification to AmerenUE's fuel adjustment clause outside the context of a prudence review process could lead investors to conclude either that AmerenUE was improperly managing its net

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[259] Barnes Additional Direct – FAC, Ex. 122, Page 8, Lines 10-11.

[260] Mantle Supplemental Direct – FAC, Ex. 221, Page 12, Lines 15-16.

[261] Transcript, Page 2517, Lines 17-23.

[262] Mantle Supplemental Direct – FAC, Ex. 221, Page 6, Lines 3-7.

fuel costs, or that the Commission was acting rashly in overturning regulatory stability in Missouri.[263] Julie Cannell, another witness for AmerenUE, explained that investors value certainty, fairness, stability, and predictability. She indicated "a lack of consistency in a commission's actions or decisions serves to increase the investment risk associated with a utility."[264] Increased financial risk results in an increase in a company's cost of borrowing, ultimately increasing costs that will be passed on to ratepayers.[265]

Conclusions of Law:

A. Section 386.266.1, RSMo (Supp. 2009), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:

[263] Rygh Rebuttal – FAC, Ex. 120, Pages 5-6, Lines 20-23, 1-5. Rygh is a Managing Director at Barclays Capital, Inc., an investment bank in New York.

[264] Cannell Rebuttal, Ex. 117, Pages 25-26, Lines 21, 1-2. Cannell is a securities analyst in New York.

[265] Cannell Rebuttal – FAC, Ex. 118, Page 5, Lines 2-3.

> *(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;*
>
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
>
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …
>
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows AmerenUE to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

B. Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

C. Specifically, Commission Rule 4 CSR 240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. AmerenUE has met those filing requirements.

Decision:

The Commission concludes AmerenUE should be allowed to continue to implement the fuel adjustment clause the Commission approved in the company's last rate case. Given the short amount of time AmerenUE's fuel adjustment clause has operated and the resulting lack of information about how effective the current sharing mechanism has been, the Commission will not modify that clause, except as provided in the previously approved stipulation and agreement. The Commission expects to further review AmerenUE's fuel adjustment clause and the appropriate sharing mechanism to be included in that clause as part of AmerenUE's next rate case.

9. Rate Design and Class Cost of Service Issues

a. Rate Design

Findings of Fact:

Introduction:

1. After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among AmerenUE's customer classes. The basis principle guiding that decision is that the customer class that causes a cost should pay that cost.

2. During the course of the hearing, Public Counsel, MIEC, AARP and the Consumers Council of Missouri, and the Missouri Retailers Association filed a nonunanimous stipulation

and agreement that reached an agreement on how the rate increase should be allocated to the customer classes. AmerenUE and Staff did not sign the stipulation and agreement but do not oppose the compromise agreement. MEUA, however, does oppose that agreement. Subsequently, the parties that signed the original stipulation and agreement submitted an addendum to that stipulation and agreement. MEUA also opposed the addendum.

3. Because the stipulation and agreement and the addendum to that stipulation and agreement are opposed, the Commission cannot approve the stipulation and agreement or the addendum. Nevertheless, the compromise described in the stipulation and agreement and addendum remains the position of the signatory parties and the Commission can consider that position as it decides this issue.

4. AmerenUE has seven customer classes.[266] The Residential class is comprised of residential households. The Small General Service and Large General Service classes are comprised of commercial operations of various sizes. The first three classes receive electric service at a low secondary voltage level. The Small Primary Service and the Large Primary Service are larger industrial operations that receive their electric service at a high voltage level. The Large Transmission Service class takes service at a transmission voltage level.

5. There is only one member of the Large Transmission class, Noranda Aluminum, Inc.[267] Noranda operates an aluminum smelter in Southeast Missouri and purchases

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[266] Cooper Direct, Ex. 134, Page 4, Lines 8-22.

[267] Staff's Class Cost-Of-Service and Rate Design Report, Ex. 205, Page 27, Lines 17-18.

massive amounts of electricity from AmerenUE. When the smelter is at full production, Noranda pays AmerenUE approximately $140 million per year for electricity[268]

6. AmerenUE's last customer class is the Lighting class, which consists of both area and street lighting.[269] The Lighting class has a unique load pattern in that it is on at night and, for the most part, off during the day. For that reason, its class load is typically very low during periods of peak demand.[270]

Specific Findings of Fact:

7. To evaluate how best to allocate costs among these customer classes, four parties prepared and presented class cost of service studies. The studies presented by AmerenUE and MIEC used versions of the Average and Excess Demand Allocation method (A&E). An A&E allocation method considers both the maximum rate of use (demand) and the duration of use (energy). The A&E method conceptually splits the system into an average component and an excess component. The average demand is the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system excess demand is the difference between the system peak demand and the system average demand. The average demand is allocated to the various classes in proportion to their average demand (energy usage). The difference between the system average demand and the system peak or peaks is then allocated to customer classes on the basis of a measure that represents their peaking or variability in usage [271]

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[268] Gregston Direct, Ex. 422, Page 3, Lines 5-14.

[269] Cooper Direct, Ex. 134, Page 4, Lines 15-16.

[270] Staff's Class Cost-Of-Service and Rate Design Report, Ex. 205, Page 12, Lines 15-16.

[271] Brubaker Direct, Ex. 429, Pages 23-24, Lines 15-22, 1-5.

8. Staff and Public Counsel also presented class cost of service studies, but they used a different allocation method known as a Peak and Average Demand Allocation method. Staff's allocation method is based on the assumption that an electric utility adds capacity to meet its entire load rather than to just meet its peak load demand.[272] Public Counsel also presented a second study using a time of use method.

9. The following chart compares the results of each of the class cost of service studies, indicating the percent change in class revenues required to equalize class rates of return, as well as the dollar amounts needed to bring a class to its indicated cost of service. A negative number means the class is paying more than its indicated share of costs. A positive number means the class is paying less than its indicated share. All dollar figures are in millions.

Study	Residential	Small General Service	Large General Service	Large Primary Service	Large Transmission Service
Staff - 4 CP A&P[273]	8.67% $83.5	-4.24% $(10.5)	-11.40% ($73.7)	-0.55% ($0.9)	3.57% $5.0
AmerenUE[274]	7.99% $78.0	-7.01% ($17.6)	-9.74% ($64.8)	1.21% $2.1	1.63% $2.3
OPC (TOU)	1.23% $11.8	-9.40% ($23.3)	-3.77% ($24.4)	8.80% $14.7	15.27% $21.2
OPC (A&P)[275]	3.35% $32.2	-7.60% ($18.9)	-4.69% ($30.3)	7.17% $12.0	3.56% $5.0
MIEC[276]	13.30% $129.6	-4.30% ($10.7)	-12.70% ($84.6)	-7.40% ($12.7)	-15.50% ($21.6)

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[272] Scheperle Rebuttal, Ex. 207, Page 2, Lines 13-19.

[273] Ex. 553.

[274] Ex. 551.

[275] Ex. 552.

[276] Brubaker Revised Direct, Ex. 429, Schedule MEB-COS-5.

For example, Staff's study indicated the Residential class is currently paying $83.5 million less than AmerenUE's cost to serve that class. In contrast, according to Staff's study, the Large General Service class is currently paying $73.7 million more than AmerenUE's cost to serve that class. Although the exact numbers vary among the various studies, all the studies agree that the Residential class is currently paying substantially less than its cost of service and that the Large General Service class is currently paying substantially more than its cost of service.

10. In starting the process to develop just and reasonable rates, the first question the Commission must resolve is which of the submitted class cost of service studies best describes AmerenUE's cost to serve its various customer classes. As a first step, the Commission will discard the Staff and Public Counsel studies that utilize a Peak and Average Demand production demand allocation method.

11. Staff asserts that its Peak and Average Demand allocation method is superior to the Average and Excess method because it considers each class' contribution to the system's total peak rather than each class' excess demand at peak.[277] However, what Staff describes as its method's strength is actually its downfall because the Peak and Average demand method double counts the average demand of the customer classes.

12. Some customer classes, such as large industrials, may run factories at a constant rate, 24 hours a day, 7 days a week. Therefore, their usage of electricity does not vary significantly by hour or by season. Thus, while they use a lot of electricity, that usage does not cause demand on the system to hit peaks for which the utility must build or acquire additional capacity. Another customer class, for example, the residential class, will

[277] Scheperle Rebuttal, Ex. 207, Page 5, Lines 11-14.

contribute to the average amount of electricity used on the system, but it will also contribute a great deal to the peaks on system usage, as residential usage will tend to vary a great deal from season to season, day to day, and hour to hour.

13. To recognize that pattern of usage, the Average and Excess method separately allocates energy cost based on the average usage of the system by the various customer classes. It then allocates the excess of the system peaks to the various customer classes by a measure of that class' contribution to the peak. In other words, the average and excess costs are each allocated to the customer classes once.

14. The Peak and Average method, in contrast, initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various classes to the cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak. Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time. Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable.[278]

15. Public Counsel also offered a time of use study that assigns production costs to each hour of the year that the specific production occurs. The method then sums each class' share of hourly investments based on only those hours when the class actually uses the system.[279] Public Counsel's time of use method is also unreliable because it considers every hour in the year to be a demand peak. As a result, the actual peaks in usage are given no additional weight. This, of course, benefits the residential class, which tends to

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[278] Brubaker Rebuttal, Ex. 430, Pages 12-14. See also, Transcript, Pages 3095-3096, Lines 24-25, 1-22.

[279] Meisenheimer Direct, Ex. 307, Page 7, Lines 5-7.

drive peaks, at the expense of industrial users of electricity that have high load factors and contribute little to the peaks in usage.[280]

16. Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC. That task is difficult in this case because most of the testimony offered by AmerenUE and MIEC's witnesses criticize the methods used by Staff and Public Counsel and offer little criticism of each others studies. Yet, the studies do reach different results.

17. Significantly, MIEC's study tends to shift more cost causation from the Large General Service, Large Primary Service and especially the Large Transmission Service classes to the Residential class than does the AmerenUE study. AmerenUE's witness, William Warwick, explained those cost shifts in his rebuttal testimony.[281] In the allocation of transmission costs, non-fuel generation expenses, off-system sales revenue, and general plant, MIEC advocated modifications to AmerenUE's study that would tend to decrease the allocation of those costs to the large industrial customers who are the members of MIEC.[282] AmerenUE contends most of these adjustments are inappropriate.

18. However, AmerenUE's witness agrees that one of the adjustments proposed by MIEC's witness is credible. In his class cost of service study, MIEC's witness, Maurice Brubaker allocated revenues from off-system sales to customer classes on the basis of class energy (kWh) requirements.[283] Staff made a similar allocation of revenues in its class

[280] Brubaker Rebuttal, Ex. 430, Page 18, Lines 12-19.

[281] Warwick Rebuttal, Ex. 147.

[282] Warwick Rebuttal, Ex. 147, Pages 2-8.

[283] Brubaker Direct, Ex. 429, Page 30, Lines 11-14.

cost of service study, and AmerenUE's witness concedes that such an allocation could be appropriate.[284] In addition, Brubaker's allocation is consistent with the methodology the Commission approved in a slightly different context in a recent Kansas City Power & Light rate case, ER-2006-0314.[285]

19. If AmerenUE's class cost of service study is modified to allocate revenues from off-system sales on the basis of class energy requirements, then that study would show that the large transmission service class is currently paying approximately 8 percent more than its indicated revenue share. The revised study would also show that the large general service class is overpaying by 11 percent and the residential class is underpaying by 11 percent.

20. After carefully considering all the studies, the Commission finds that AmerenUE's class cost of service study, modified to allocate revenues from off-system sales on the basis of class energy requirements, is the most reliable of the submitted studies.

21. Evaluating the submitted class cost of service studies is only the Commission's first step in designing just and reasonable rates for AmerenUE. In general, it is important that each customer class carry its own weight by paying rates sufficient to cover the cost to serve that class. That is a matter of simple fairness in that one customer class should not be required to subsidize another. Requiring each customer class to cover its actual cost of service also encourages cost effective utilization of electricity by customers by sending correct price signals to those customers.[286] However, the Commission is not required to precisely set rates to match the indicated class cost of service. Instead, the Commission

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[284] Warwick Rebuttal, Ex. 147, Pages 5-7.

[285] Brubaker Direct, Ex. 429, Page 30, Line 14.

[286] Cooper Direct, Ex. 134, Pages 16-17, Lines 13-22, 1-2.

has a great deal of discretion to set just and reasonable rates, and can take into account other factors, such as public acceptance, rate stability, and revenue stability in setting rates.

22. AmerenUE and, initially, Public Counsel, proposed that any rate increase should be allotted equally to each customer class. In other words, each class would receive the system average percentage increase.[287] That would leave the existing disparities revealed in the class cost of service studies unchanged.

23. Staff proposed that a small adjustment be made to shift $3 million in revenue responsibility from the large general service class to the residential class. Staff's adjustment would represent approximately a 0.3 percent increase in revenue responsibility to the residential class and a 0.5 percent decrease in revenue responsibility to the large general service class.[288]

24. MIEC proposed that each customer class be moved 20 percent toward its cost of service as shown in MIEC class cost of service study. That move would require a 2.6 percent revenue neutral increase from the residential class,[289] to collect $25.9 million in additional revenue from the residential class.[290] However, MIEC would not stop there: Brubaker also advocated that the Large Transmission class, whose only member is Noranda, be moved entirely to its cost of service as shown in MIEC's class cost of service

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[287] Cooper Direct, Ex. 134, Page 18, Lines 12-13. *See also*, Kind Direct, Ex. 300, Page 8, Lines 7-11.

[288] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page 24, Lines 8-15.

[289] Brubaker Revised Direct, Ex. 429, Page 36, Lines 13-19.

[290] Brubaker Revised Direct, Ex. 429, Schedule MEB-COS-6.

study. That extra movement would require an additional $8.2 million from the residential class and would reduce the rate relief that would otherwise flow to the other rate classes.[291]

25. Finally, MEUA, whose members take electric service as part of the large general service class, recommended the Commission adopt MIEC's proposed 20 percent revenue neutral adjustment, but without the extra adjustment to move the large transmission class to its cost of service.[292]

26. The stipulation and agreement to which MEUA objected would shift revenue responsibility to the residential, small general service and large primary service classes from the large transmission class and to a lesser extent, the large general service and small primary service classes. The addendum to the stipulation and agreement, to which MEUA also objected, would allocate a slightly larger revenue responsibility reduction to the large general service class.

27. Specifically, for an overall rate increase of $225 million, which is approximately the rate increase that will result from this order, the addendum to the stipulation and agreement would impose a roughly 1.5 percent revenue-neutral increase on the residential and small general service classes. That amounts to a revenue neutral increase of $14.5 million for the residential class and $3.8 million for the small general service class. It would also impose a 1.25 percent revenue neutral increase, amounting to an additional $2 million, on the large primary class.

28. On the other side of the coin, the large transmission class, whose only member is Noranda, would receive a revenue neutral reduction of 11.74 percent, which amounts to a reduction of approximately $16.3 million. That means Noranda would receive an actual

[291] Brubaker Revised Direct, Ex. 429, Schedule MEB-COS-6.

[292] Chriss Rebuttal, Ex. 550, Page 11, Lines 3-12.

rate reduction of approximately $2.1 million, or a 1.54 percent overall reduction. That would occur while the residential class received an 11.70 percent rate increase. The large general service/small primary service class would receive a smaller revenue neutral reduction of 0.7%, amounting to $4.579 million. That means the large general service/small primary service class would receive an overall rate increase of 9.59 percent.

29. The reallocation of revenue responsibility the signatories agreed to in the stipulation and agreement, now their joint position, bears some resemblance to the results of AmerenUE's modified class cost of service study, which the Commission found to be the most reliable of the submitted studies. AmerenUE's study, and indeed, all the submitted studies, indicate that the residential class is paying substantially less than its actual revenue responsibility. The stipulated position would bring that revenue class closer to its actual cost of service. The stipulated position would also provide the large transmission service class, Noranda, with the largest rate reduction, even though AmerenUE's modified class cost of service study indicates the large general service class is currently overpaying its actual cost of service by a larger percentage.

30. MIEC, and in particular, Noranda, attempt to justify these results by claiming that Noranda needs special rate consideration to remain competitive with other aluminum smelters in the United States, lest it be forced to close, resulting in economic devastation to Missouri.

31. There is no doubt that the closure of Noranda's New Madrid aluminum smelter would have a severe impact on the economy of Southeast Missouri. Noranda directly employs some 900 people at its smelter, at an annual payroll of $60 million. Were the plant to close,

the Southeast Missouri region could lose over 3,200 jobs from its economy and state and local governments would lose $16 million per year in tax revenues.[293]

32. Noranda's aluminum smelter produces molten aluminum from aluminum oxide, known as alumina. The alumina is brought up the Mississippi river by barge for delivery to the smelter.[294] The processing of the alumina into aluminum requires a tremendous amount of electricity. When the smelter is at full production, at current electric rates, Noranda pays AmerenUE $140 million for electricity each year. The cost of electricity represents a little less than one-third of the smelter's cost of producing aluminum.[295]

33. Electricity is not the only cost factor affecting the continued viability of the New Madrid smelter, and MEUA demonstrated that the New Madrid smelter appears to possess certain competitive advantages over other competing smelters apart from the cost of electricity. For example, the smelter's geographic location on the Mississippi river reduces its cost to transport supplies of alumina.[296] If the market price of aluminum rises, Noranda may also benefit from paying a fixed rate for electricity while many of its competitors pay a rate for electricity that varies with the market price of aluminum.[297] Noranda expects that aluminum prices will rise in the future.[298] Still, while there is no evidence to indicate that Noranda is on the verge of shutting down its smelter with or without an electric rate increase, the smelter's long-term viability is dependent upon maintaining reasonably competitive electric rates.

[293] Coomes Direct, Ex. 419, Page 2, Lines 4-12.
[294] Gregston Direct, Ex. 422, Page 1, Lines 12-17.
[295] Gregston Direct, Ex. 422, Page 3, Lines 5-14.
[296] Transcript, Page 2948, Lines 17-21.
[297] Transcript, Page 2948, Lines 2-7.
[298] Transcript, Page, 2959, Lines 1-5.

34. The large general service customer class is also currently paying more than its indicated revenue share and the stipulated position would provide that class with $4,579,000 of rate relief. But no evidence was presented that would show that the members of the large general service customer class need rate relief to remain competitive in the same way that Noranda needs that relief.

35. Clearly, Noranda will be affected by the rate increase that will result from this case. But the same can be said about all the other businesses and families that must pay AmerenUE for the electricity they need. The reduction proposed by the stipulated position would give Noranda an actual rate decrease of $2.147 million while all other customers have to absorb a rate increase. That result is inappropriate. While generally accepting the joint position, the Commission will modify that position to provide that the revenue neutral reduction in the large transmission service class's rate shall be set at a level that leaves that class' total revenue contribution unchanged. The joint position's revenue increase for the residential class shall be reduced by the amount taken from the large transmission class' revenue reduction. The lighting class' class revenue responsibility will be addressed in the next section of this report and order.

36. The objected to stipulation and agreement also purports to resolve certain issues regarding customer charges, Rider B voltage credits, and the Reactive Charge. No party, including MEUA, objects to that aspect of the stipulation and agreement.[299]

37. Specifically, the signatories agree that the residential customer charge should be set at $8.00 per month, with the remaining revenue assigned to the residential class to be allocated to volumetric charges. AmerenUE proposed that the residential customer charge

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[299] *See.* Initial Posthearing Brief of Midwest Energy Users Association, Page 11.

be increased to $10.00 per month from its current level of $7.25.[300] Staff recommended the residential customer charge be increased to $8.50 per month.[301] However, neither Staff nor AmerenUE objects to a residential customer charge of $8.00 per month. The Commission finds that $8.00 per month is a reasonable residential customer charge.

38. The signatories also agree as follows:

> the Small Power Service (SPS), Large Primary Service (LPS) and Large Transmission Service (LTS) customer charges should be set to $234.33, then those customer charges should be increased by the same percentage as the system average percentage increase, i.e., each will be increased by the same percentage and each will be the same. The signatories agree the rates for Rider B voltage credits (Tariff Sheet 99) should remain the same for all applicable rate schedules. The existing Rider B voltage credits should be increased by the same percentage as the system average percentage increase. The particular Rider B voltage credits as they now exist follow:
>
> - A monthly credit of $0.90/kW of billing demand for customers taking service at 34.5 or 69kV.
> - A monthly credit of $1.06/kW of billing demand for customers taking service at 115kV or higher.
>
> The Signatories agree the rate for the Reactive Charge should be the same for all applicable rate schedules and that the existing Reactive Charge should be increased by the same percentage as the system average percentage increase. The current Reactive Charge for SPS (Tariff Sheet 37), LPS (Tariff Sheet 67.1) and LTS (Tariff Sheet 68) classes are $027 per kVar. The Signatories agree the customer charge associated with Time-of-Day rates should be the same for all applicable non-residential rate schedules and that the existing Time-of-Day customer charge should be increased by the same percentage as the system average percentage increase. The current Time-of-Day customer charge for the Large General Service class (LGS)(Tariff Sheet 34), SPS (Tariff Sheet 37, LPS (Tariff Sheet 67.1) and LTS (Tariff Sheet 68) is $15.25. The Signatories agree the Small General Service class (SGS) customer charge should be $9.28 for single-phase service and $18.56 for three-phase service (Tariff Sheet 32). With the foregoing exceptions, all other rate elements within each rate schedule shall be increased by an equal percentage basis so that collectively all rate elements on that schedule are designed to collect the revenue assigned to the class to which that rate schedule applies.

[300] Cooper Direct, Ex. 134, Page 21, Lines 1-7.

[301] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page 24, Line 18.

The agreed upon positions are generally consistent with the positions taken by Staff and AmerenUE and neither party has objected to those positions. The Commission finds that the agreed upon positions stated in the stipulation and agreement are reasonable and the Commission adopts those positions.

39. The signatories also agreed to adopt Staff's position that the following features should be returned to uniformity:

- The value of the customer charge be uniform across rate schedules, with the customer charges on the SPS, LPS, and LTS rate schedules being the same.
- The rates for Rider B voltage credits be the same under all applicable rate schedules.
- The rates for the Reactive Charge be the same for all applicable rate schedules.
- The rates associated with Time-of-Day meter charge be the same for all applicable non-residential rate schedules.[302]

Staff's testimony explained that these features had been uniform until implementation of the rate design in AmerenUE's last rate case. The Commission finds that the agreed upon position is reasonable and that position is adopted.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission generally accepts the joint position, but will modify that position to provide that the revenue neutral reduction in the large transmission service class's rate shall be set at a level that leaves that class' total revenue contribution unchanged. The joint position's revenue increase for the residential class shall be reduced by the amount

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[302] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page24, Lines 1-6.

taken from the large transmission class' revenue reduction. The lighting class' class revenue responsibility will be addressed in the next section of this report and order.

b. Street Lighting

Findings of Fact:

Introduction:

40. The members of the lighting class of customers largely consists of municipalities that purchase electricity from AmerenUE to light their streets at night. The lighting class has a unique load pattern in that the street lights are generally on only at night. That means street lights are drawing power when demand from other users tends to be low, and as a result the lighting class does not contribute much to peak demand. As previously discussed, peak demand tends to drive costs, so the lighting class does not fit well into a general class cost of service study.[303] For that reason, the class cost of service studies submitted by Staff and AmerenUE did not separately calculate the cost of serving the lighting class. Instead, their cost of service studies allocated all direct lighting costs and revenues to the other classes based on each class' share of AmerenUE's total cost-of-service.[304] That allocation method assumes that the company's rates for lighting service have been established at or near their cost of service,[305] but it does not actually determine whether that assumption is correct.

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[303] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page 12, Lines 15-21.

[304] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page 12, Lines 21-25.

[305] Staff's Class Cost-of-Service and Rate Design Report, Ex. 205, Page 13, Lines 1-3. *See also*, Warwick Direct, Ex. 146, Page 4, Lines 1-15.

41. The same allocation method was used in AmerenUE's last two rate cases, and no actual cost of service study has been done for the lighting class over that time.[306] AmerenUE may have last performed a comprehensive street lighting study sometime in the1980's but it has been unable to locate that study.[307] Since AmerenUE's cost to serve the lighting class has not been studied since at least the 1980's, the lighting class has simply been allocated the same across the board rate adjustments allocated to the other rate classes. AmerenUE and Staff would continue that practice in this case.

42. The lighting class has not been represented in AmerenUE's previous rate cases, but the Municipal Group intervened in this case to bring the lighting class' issues to the Commission's attention. In the First Stipulation and Agreement, filed on March 10, before the start of the hearing, the signatory parties agreed that AmerenUE would cooperate with all interested parties in preparing a cost of service study regarding the lighting class for use in the company's next rate case.[308] The Municipal Group did not sign that stipulation and agreement, but it did not oppose it, and the Commission approved the stipulation and agreement on March 24.[309]

43. Despite the stipulation and agreement's provision for a future class cost of service study, the Municipal Group continues to seek immediate relief in this case. Specifically, the Municipal Group seeks:

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[306] Transcript, Page 2871, Lines 3-20.

[307] Transcript, Page 2872, Lines 1-4.

[308] First Nonunanimous Stipulation and Agreement, Page 7.

[309] In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase Its Annual Revenues for Electric Service, File No. ER-2010-0036, Order Approving First Stipulation and Agreement (March 24, 2010).

1. A moratorium on any new street lighting rates under the 5M and 6M tariffs pending the outcome of the cost of service study and its introduction in AmerenUE's next rate case, or, in the alternative that AmerenUE hold in escrow any increase ordered for the 5M and 6M street lighting rates pending the review of the street lighting cost of service study in AmerenUE's next rate case; and

2. The elimination of any future pole installation charges from 5M customer bills until such pole installation charges can be justified in AmerenUE's next rate case; and

3. A credit for the 5M customers for all other revenues received by AmerenUE for itself and other entities for their use of these same poles for telephone, cable TV, electric distribution lines, etc.[310]

Specific Findings of Fact:

44. AmerenUE currently collects roughly $31 million per year system-wide from the lighting class.[311] That represents about 1.4 percent of the company's total base rate revenues.[312] The company collects a part of that revenue from its 5M and 6M rates for street lighting, but the exact amount AmerenUE collects under those two particular rates is not revealed in the record.

45. The 5M classification is for street lights that are owned and maintained by AmerenUE. Those street lights are not metered. Instead, the 5M customer is billed by

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[310] Initial Brief of the Municipal Group, Pages 10-11.

[311] Transcript, Page 2869, Lines 6-15.

[312] Warwick Direct, Ex. 146, Page 4, Lines 11-12.

fixture and pole type according to the number of lights in each rate category.[313] The street lighting bill can be a significant expense for a municipality. For example, the City of University City budgets approximately $640,000 per year for 5M street lighting.[314] The 6M classification covers metered and unmetered street lighting that is owned by the customer rather than AmerenUE.[315]

46. After comparing the 5M rate to the 6M rate, the Municipal Group contends it is being overcharged for maintenance portion of the 5M rate.[316] The Municipal Group also contends it is being overcharged under the 5M rate for pole installation charges for poles installed before 1988. The Municipal Group claims that having collected an installation charge for more than 20 years, AmerenUE should have recovered its installation costs by now.[317]

47. Finally, the Municipal Group notes that AmerenUE collects revenue from other entities for various installations added onto the street lighting poles, such as cable TV lines. The municipalities contend that since they are in effect renting the poles, they should receive a cut of that revenue.[318] AmerenUE explains that it accounts for that extra revenue as an offset to its base rate revenues in its rate cases. In other words, a dollar collected from a cable company for hanging a line on a light pole would be a dollar the company would not collect from its customers, including the lighting customers.[319] Thus, the Commission finds that those revenues do, at least indirectly benefit the lighting customers.

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[313] Eastman Rebuttal, Ex. 750, Page 4, Lines 3-13.
[314] Eastman Rebuttal, Ex. 750, Page 4, Lines 15-17.
[315] Eastman Rebuttal, Ex. 750, Page 6, Lines 11-14.
[316] Eastman Rebuttal, Ex. 750, Page 9-11.
[317] Eastman Rebuttal, Ex. 750, Page 14, Lines 5-18.
[318] Transcript, Pages 2878-2880.
[319] Transcript, Page 2878, Lines 11-20.

48. AmerenUE generally denies that it is overcharging its lighting customers, but concedes that there is no specific cost study to support those rates. That deficiency should be corrected by the completion of such a cost study for the development of rates in the company's next rate case. The Municipal Group claims that pole installation charges are unfair, but could offer nothing other than speculation to prove that contention. Since there is no basis at this time to conclude that the current rates are not justified, the Commission will not eliminate future pole installation charges at this time. But the fairness of those charges should become clearer after completion of the costs study and may be revisited in the next rate case.

49. The record does not indicate the amount of revenue AmerenUE collects from 5M and 6M rates apart from the general lighting revenue numbers. Therefore, the Commission cannot exempt just the 5M and 6M ratepayers from the increased rates that will result from this rate case. However, because no class cost of service study has examined the lighting class since at least the 1980s, the entire class has been given rates that may or may not bear any resemblance to the cost to serve that class. The lighting class is only a small part of AmerenUE's entire customer base, but street lighting is a significant cost for the municipalities that take that service. Under the circumstances, the Commission will exempt the entire lighting customer class from the rate increase that will result from this report and order.[320]

50. The lighting class currently generates $31.295 million in revenue for AmerenUE. The roughly 10.2 percent system average rate increase that will result from this case would

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[320] The Municipal Group's alternative proposal to have AmerenUE hold the rate increase collected from the lighting group in escrow, subject to refund, would not be fair to AmerenUE because, if the lighting group's rates were found to be too high, the company would not be able to go back and collect any revenue shortfall after the fact from the other customer classes.

generate an additional $3.2 million in revenue from the lighting class. AmerenUE shall instead collect that $3.2 million of revenue from the other rate classes on a pro rata basis.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The entire lighting class is exempted from the rate increase that will result from this report and order. The additional revenue that would have been collected from the lighting class under a system average rate increase shall instead be collected from the other rate classes on a pro rata basis. The adjustments necessary to exempt the lighting class shall be made after the general adjustments made pursuant to section 9a of this Report and Order.

IT IS ORDERED THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a AmerenUE on July 24, 2009, and assigned tariff number YE-2010-0054, are rejected.

2. Union Electric Company, d/b/a AmerenUE is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order. AmerenUE shall file its compliance tariff no later than June 8, 2010.

3. This report and order shall become effective on June 7, 2010.

BY THE COMMISSION

(S E A L)

Steven C. Reed
Secretary

Davis, C., concurs, with concurring opinion to follow,
Jarrett, Gunn, and Kenney, CC., concur,
Clayton, Chm., dissents, with dissenting opinion to follow.
and certify compliance with the provisions
of Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 28th day of May, 2010.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a	)	**File No. ER-2012-0166**
Ameren Missouri's Tariff to Increase Its Annual	)	Tariff No. YE-2012-0370
Revenues for Electric Service	)	

REPORT AND ORDER

Issue Date: December 12, 2012

Effective Date: December 22, 2012

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Annual Revenues for Electric Service	)))	**File No. ER-2012-0166** Tariff No. YE-2012-0370

APPEARANCES

Thomas M. Byrne, Managing Assoc. General Counsel, and **Wendy K. Tatro**, Asst. General Counsel, Ameren Services Company, P.O. Box 66149, 1901 Chouteau Ave., St. Louis, Missouri 63103;

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For the Missouri Retailers Association.

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For Natural Resources Defense Council, Sierra Club, and Earth Island Institute d/b/a Renew Missouri.

Larry W. Dority, Attorney at Law and **James M. Fischer**, Attorney at Law, FISCHER & DORITY, PC, 101 Madison St., Suite 400, Jefferson City, Missouri 65101

For Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company.

Sherrie A. Hall, Attorney at Law, **Michael A. Evans**, Hammond and Shinners, P.C. 7730 Carondelet Ave., Suite 200, St. Louis, Missouri 63105.

For International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, 1455, AFL-CIO and International Brotherhood of Operating Engineers Local 148, AFL-CIO.

CHIEF REGULATORY LAW JUDGE: Morris L. Woodruff

REPORT AND ORDER

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The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Summary

This order allows Ameren Missouri to increase the revenue it may collect from its Missouri customers by approximately $260.2 million, based on the data contained in the Revised True-up Reconciliation filed by the Missouri Public Service Commission Staff on October 12, 2012.[1] Over $100 million of that increase is related to Ameren Missouri's increased net fuel costs and would otherwise be recoverd by the company through its fuel adjustment clause. Another $89 million of that increase is for the cost of increasing Ameren Missouri's energy efficiency efforts under Missouri's Energy Efficiency Investment Act, MEEIA. Those efforts will enable Ameren Missouri's customers to take steps to decrease their usage of electricity and thereby decrease their electric bills.

Procedural History

On February 3, 2012, Union Electric Company, d/b/a Ameren Missouri filed a tariff designed to implement a general rate increase for electric service. The tariff would have increased Ameren Missouri's annual electric revenues by approximately $375.6 million. The tariff revisions carried an effective date of March 4, 2012.

By order issued on February 6, 2012, the Commission suspended Ameren Missouri's general rate increase tariff until January 2, 2013, the maximum amount of time allowed by the controlling statute.[2] In the same order, the Commission directed that notice of Ameren Missouri's tariff filing be provided to interested parties and the public. The

[1] This number is only an estimate of the overall impact of the decisions described later in this report and order. This estimate does not in any way control or modify those decisions.

[2] Section 393.150, RSMo 2000.

Commission also established February 23, 2012, as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: The International Brotherhood of Electrical Workers Locals 2, 309, 649, 702, 1439, and 1455, AFL-CIO and International Union of Operating Engineers Local 148 AFL-CIO (collectively the Unions); The Missouri Industrial Energy Consumers (MIEC);[3] The Midwest Energy Consumers Group (MECG);[4] Barnes-Jewish Hospital; The Missouri Department of Natural Resources (MDNR); Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company; The Consumers Council of Missouri; AARP; The Missouri Retailers Association; and The Sierra Club, Earth Island Institute d/b/a Renew Missouri and the Natural Resources Defense Council (collectively Sierra Club). On March 28, 2012, the Commission established the test year for this case as the 12-month period ending September 30, 2011, trued-up as of July 31, 2012. In its March 28 order, the Commission also established a procedural schedule leading to an evidentiary hearing.

In July and August 2012, the Commission conducted twelve local public hearings at various sites around Ameren Missouri's service area. At those hearings, the Commission heard comments from Ameren Missouri's customers and the public regarding Ameren Missouri's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on September 27, 2012, and continued through October 11. The parties indicated they had no contested true-up

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[3] The members of MIEC are as follows: Anheuser-Busch Companies, Inc.; BioKyowa, Inc.; The Boeing Company; Covidien; Doe Run; Enbridge; Explorer Pipeline; General Motors Corporation; GKN Aerospace; Hussmann Corporation; JW Aluminum; MEMC Electronic Materials; Monsanto; Proctor & Gamble Company; Nestlé Purina PetCare; Noranda Aluminum; and Saint Gobain.

[4] The members of MECG are Walmart Stores, Inc. and JC Penney.

issues and the Commission cancelled the scheduled true-up hearing. The parties filed post-hearing briefs on November 5, with reply briefs following on November 15.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed six nonunanimous partial stipulations and agreements resolving issues that would otherwise have been the subject of testimony at the hearing. No party opposed five of those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[5] After considering the stipulations and agreements, the Commission approved them as a resolution of the issues addressed in those agreements. The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

The sixth nonunanimous stipulation and agreement was signed by Ameren Missouri, Staff, and MIEC, and was filed on November 2. That stipulation and agreement dealt with some rather technical matters regarding 1) class kilowatt-hours, revenues and billing determinants; 2) fuel costs purchased power costs, off-system sales revenues and base factors; and 3) fuel adjustment clause tariff sheets. On November 9, AARP and Consumers Council filed a timely objection to that stipulation and agreement.

AARP and Consumers Council object to the stipulation and agreement because it purports to resolve all issues regarding Ameren Missouri's fuel adjustment clause (FAC) except the FAC-related issues specifically excepted from the settlement. That is, the stipulation and agreement assumes the Commission will approve a Fuel Adjustment Clause

[5] Commission Rule 4 CSR 240-2.115(C).

in this case, a result that would be contrary to AARP and Consumers Council's position. AARP and Consumers Council did not request any additional hearings regarding the stipulation and agreement other than the evidentiary hearing that was already held.

As provided in the Commission's rules, the Commission will treat that stipulation and agreement as merely a position of the signatory parties to which no party is bound.[6] The issues that were the subject of that stipulation and agreement will be determined in this report and order.

Overview

Ameren Missouri is an investor-owned integrated electric utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. Ameren Missouri has approximately 1.2 million retail electric customers in Missouri, more than 1 million of whom are residential customers.[7] Ameren Missouri also operates a natural gas utility in Missouri but the rates it charges for natural gas are not at issue in this case.

Ameren Missouri began the rate case process when it filed its tariff on February 3, 2012. In doing so, Ameren Missouri asserted it was entitled to increase its retail rates by approximately $376 million per year, an increase of approximately 14.6 percent.[8] Ameren Missouri claimed a rate increase was necessary due to increases in net fuel costs, significant investments in infrastructure, significantly expanded energy efficiency programs, reduced normalized revenues due to decreased demand for electricity, higher

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[6] Commission Rule 4 CSR 240-2.115(2)(D).

[7] Baxter Direct, Ex. 1, Page 5, Lines 1-2.

[8] Baxter Direct, Ex. 1, Page 5, Lines 20-21.

pension/OPEB and medical costs, and higher operating costs.[9] The company attributed $103 million of that increase to the rebasing of fuel costs that would otherwise be passed through to customers by operation of the company's existing fuel adjustment clause.[10]

Ameren Missouri set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on February 3, 2012. In addition to its filed testimony, Ameren Missouri provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review Ameren Missouri's testimony and records to determine whether the requested rate increase was justified.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On September 21, 2012, the parties filed a list of the issues they asked the Commission to resolve. The Commission will address those issues in the order submitted by the parties.

Conclusions of Law Regarding Jurisdiction

A. Ameren Missouri is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Supp. 2011). As such, Ameren Missouri is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo 2000.

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[9] Baxter Direct, Ex. 1, Pages 5-6, Lines 21-23, 1-10.

[10] Baxter Direct, Ex. 1, Page 8, Lines 1-2.

B. Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates Ameren Missouri may charge its customers for electricity. When Ameren Missouri filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

Conclusions of Law Regarding the Determination of Just and Reasonable Rates

A. In determining the rates Ameren Missouri may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[11] Ameren Missouri has the burden of proving its proposed rates are just and reasonable.[12]

B. In determining whether the rates proposed by Ameren Missouri are just and reasonable, the Commission must balance the interests of the investor and the consumer.[13] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[14]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the

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[11] Section 393.150.2, RSMo 2000.

[12] Section 393.150.2, RSMo 2000.

[13] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).

[14] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

> property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[15]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[16]

C. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[17]

D. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

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[15] *Bluefield,* at 692-93.

[16] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

[17] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[18]

The Rate Making Process

The rates Ameren Missouri will be allowed to charge its customers are based on a determination of the company's revenue requirement. Ameren Missouri's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return
R = Return requirement
(V-AD+A) = Rate base
For the rate base calculation:
V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

The Issues

1. Regulatory Policy and Economic Considerations:

This is not a true issue in that the parties do not ask the Commission to resolve any questions regarding the particulars of Ameren Missouri's request for a rate increase. Instead, the parties presented testimony regarding general policy matters that affect the

[18] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

Commission's decision making regarding the detailed issues that will be addressed later in this report and order. Because this is only a general policy discussion, the Commission will not make findings of fact or conclusions of law about these policy matters.

A great deal of testimony was offered by the parties regarding the difficult economic situation that is currently facing individuals and businesses in Missouri in general and in Ameren Missouri's service territory in particular. Aside from the testimony offered at the evidentiary hearing, the Commission also heard the message of hard times loud and clear from Ameren Missouri's customers during the twelve, well-attended, local public hearings the Commission conducted throughout Ameren Missouri's service territory.

The Commission was created to serve the public interest and it takes that responsibility very seriously. The Commission serves the public interest by establishing just and reasonable rates and the Commission has endeavored to do so in this report and order.

Many customers are already having a hard time paying their electric bills. Increasing Ameren Missouri's rates may make it even harder for some customers to pay their bills. However, a just and reasonable rate does not necessarily mean a lower rate.

The Commission has said many times that no one benefits when a utility is deprived of the ability to charge its customers a just and reasonable rate. Customers may initially be happy when the rates they pay are kept low, but if a utility's rates are kept unreasonably low, the reliability of the service the utility offers will inevitably suffer. No one likes to pay increased rates, but no one likes to sit in the cold and dark when the lights go out.

The other side of the just and reasonable rate argument is offered by Ameren Missouri. The theme of much of the company's testimony and argument is that the regulatory system in Missouri is broken because Ameren Missouri has been unable to earn its allowed rate of return in recent years. In accord with that theme, Ameren Missouri has offered several ideas to fix the “broken” regulatory system, some of which the Commission has accepted, others of which it has rejected.

Perhaps Ameren Missouri’s earnings have not been as healthy in the last five years as it would like, but many of the company’s customers have also suffered from earnings that are not as large as they would like. In previous rate cases, the Commission has adopted some proposals designed to improve the regulatory system and it has adopted some additional proposals in this report and order. The Commission is willing to listen to and consider additional ideas for ways in which the system can be improved. However, what may be only a temporary downturn in the company’s earnings does not mean the current regulatory system is broken. That conclusion is reflected throughout the remaining issues addressed in this report and order.

2. Cash Working Capital:

A. Should the collection lag be calculated using the CURST 246 Report for the 12-month period ending October 31, 2010, or the Accounts Receivable Breakdown Report?

Findings of Fact:

1. Cash Working Capital is a measure of the amount of cash the company needs to keep on hand to handle its day-to-day business affairs.[19] That amount is included in rate base and the company is allowed to earn a return on that investment.[20]

2. To determine the appropriate amount to allow for Cash Working Capital, Ameren Missouri performed a lead-lag study. As the name implies, a lead-lag study has

[19] Adams Direct, Ex. 8, Page 3, Lines 13-14.

[20] Adams Direct, Ex. 8, Page 4, Lines 18-19.

two aspects. The revenue lag portion of the study seeks to determine the lag time between the date customers receive service and the date the company receives payment from those customers. The other half of the equation is the expense lead, which seeks to determine the time between when the company receives goods and services and when it pays for those goods and services.[21]

3. This issue concerns the company's collection lag, the measure of the amount of time between when Ameren Missouri sends a bill to its customers and when the company receives payment from those customers.[22]

4. Ameren Missouri presented the testimony of Michael Adams, a consultant with Concentric Energy Advisors,[23] who analyzed the company's aged accounts receivable breakdown report to support a collection lag of 28.75 days. In other words, Ameren Missouri contends that on average, it collects payment from a customer 28.75 days after it bills the customer for electric service.

5. In past rate cases, Ameren Missouri has calculated its collection lag using data from something called a CURST 246 report that the company prepared until 2010.[24] Staff and MIEC contend Ameren Missouri's current estimation of its collection lag is inflated and would instead rely on the last available CURST 246 reports.[25]

6. Staff relies on the CURST 246 report for the twelve months ending October

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[21] Adams Direct, Ex. 8, Page 5, Lines 1-13.

[22] Adams Direct, Ex. 8, Page 7, Lines 6-12.

[23] Adams Direct, Ex. 8, Page 1, Line 13.

[24] Boateng Surrebuttal, Ex. 231, Page 3, Lines 1-14.

[25] Boateng Surrebuttal, Ex. 231, Page 2, Lines 14-17 and Meyer Direct, Ex. 510, Page 20, Lines 18-19.

31, 2010 to support a collection lag of 21.11 days.[26] MIEC relies on the CURST 246 report for the twelve months ending March 2010 to support a collection lag of 21.01 days.[27] MIEC did not explain why it uses the older CURST 246 report.

7. The test year for this case is the twelve-month period ending September 30, 2011, trued-up as of July 31, 2012. Therefore, the CURST 246 reports used by Staff and MIEC present information from outside the test year. In general, the use of out-of-test-year data, violates the matching principle behind the concept of a test year.

8. The CURST 246 report was developed some 25 years ago by Ameren Missouri's IT department[28] and purportedly showed Ameren Missouri's cash receipts on a daily basis as they were collected by the company. The report was compiled for over 25 years and was used by the company solely to calculate the collection lag for rate cases.[29]

9. No other electric utility in this state uses a collection report similar to the CURST 246 report.[30] Ameren Missouri's witness testified that to his knowledge, no other utility or regulatory agency relies on the CURST 246 report, or anything like it.[31]

10. Ameren Missouri questioned the accuracy of the CURST 246 report and found that it could not be replicated or validated. After 2010, Ameren Missouri decided to stop producing the CURST 246 report.[32]

11. Neither Staff's witness, nor MIEC's witness testified to having undertaken any

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[26] Boateng Surrebuttal, Ex. 231, Page 2, Lines 14-15.

[27] Meyer Direct, Ex.510, Page 21, Lines 13-14.

[28] Transcript, Page 461, Lines 19-21.

[29] Adams Rebuttal, Ex. 9, Page 6, Lines 14-20.

[30] Adams Rebuttal, Ex. 9, Page 16, Lines 1-3.

[31] Transcript, Page 463, Lines 15-17.

[32] Adams Rebuttal, Ex. 9, Page 7, Lines 10-13.

study to verify the accuracy of the CURST 246 report.[33]

12. To calculate its collection lag, Ameren Missouri relied primarily on its Accounts Receivable Breakdown Report. When a customer is billed, an amount is added to the company's accounts receivable. When the customer pays the bill, accounts receivable are reduced by the amount of the payment. The company monitors its accounts receivable by maintaining a monthly aging report to determine which customers pay their bills on time and which accounts receivable are delinquent. The aging report indicates in aggregate which receivables are current, or within 30 days outstanding, 30-59 days outstanding, 60-89 days outstanding, 90-119 days outstanding, and 120 or more days outstanding.[34]

13. Ameren Missouri adjusted that Accounts Receivable Breakdown Report to account for those accounts receivable that would never be collected and would instead be treated as bad debt. The uncollectable amounts were removed for purposes of the collection lag calculation by removing a percentage of accounts receivable that the company believed, based on a historical analysis,[35] were likely to be uncollectable for each period.[36]

14. When his calculation of a collection lead was challenged by MIEC and Staff, Ameren Missouri's witness undertook steps to verify the accuracy of that calculation. The company provided him with five months of data from the test year showing 1) the date customers were billed; 2) the due date on the bill; and 3) the date the bill was paid in full.

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[33] Transcript, Page 479, Lines 21-24.

[34] Adams Rebuttal, Ex. 9, Page 4, Lines 9-19.

[35] Transcript, Page 471-472, Lines 22-25, 1-4.

[36] Transcript, Page 462, Lines 14-25.

Using that data, he calculated a collection lag of 32.72 days. The collection lag was calculated at 27.79 days when outstanding balances were treated as if they had been outstanding for no more than 120 days.[37]

15. As a further verification of his analysis, Ameren Missouri's witness performed a turnover ratio analysis. This is the analysis that Laclede Gas Company and Atmos Energy Corporation use to calculate their collection lag. The analysis of Ameren Missouri's turnover ratio produced a collection lag of 26.02 days, which is closer to the collection lag proposed by the company than it is to the collection lags based on the old CURST 246 reports.[38]

16. The 28.75-day collection lag utilized by Ameren Missouri is consistent with collection lags calculated for other utilities around the country, including that used by Ameren Illinois.[39]

17. Staff and MIEC raised several additional criticisms of Ameren Missouri's aged accounts receivable breakdown analysis and its proposed collection lag, but all were refuted by Ameren Missouri.

18. Staff and MIEC sought to rely on the out of test year CURST 246 report. However, they performed no analysis to demonstrate that the old report was still accurate for use in this test year or indeed that it was ever accurate. Simply relying on an old familiar report as received wisdom is not competent and substantial evidence. After reviewing the competent and substantial evidence presented on this issue, the Commission finds that the 28.75-day collection lag utilized by Ameren Missouri in its lead-lag study is a

[37] Adams Rebuttal, Ex. 9, Page 14, lines 5-10.

[38] Adams Rebuttal, Ex. 9, Page 16, Lines 16-20.

[39] Transcript, Page 467, Lines 10-22.

reasonable and accurate measure of the company's collection lag.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The appropriate collection lag to be used in Ameren Missouri's lead-lag study is 28.75 days as proposed by Ameren Missouri.

B. Should the income tax calculation be removed from Ameren Missouri's cash working capital requirement?

Findings of Fact:

1. This sub-issue concerns another aspect of Ameren Missouri's calculation of its cash working capital requirement. MIEC's witness, Greg Meyer, points out that Ameren Missouri's calculation of cash working capital includes provisions recognizing the cash requirement associated with making income tax payments to the IRS. However, he asserts that due to favorable tax provisions, Ameren Corporation has paid little or no corporate income tax in recent years. For that reason, Meyer asserts that no cash working capital requirement should be calculated for income tax expense.[40] Ameren Missouri and Staff oppose the proposed adjustment to cash working capital.

2. Ameren Missouri's witness regarding cash working capital was Michael J. Adams. Adams is Senior Vice President of Concentric Energy Advisors, Inc. Concentric is a management consulting and economic advisory firm. Adams has an MBA in finance from the University of Illinois-Springfield.[41]

3. Ameren Missouri's cash working capital analysis reflected an expense lead of

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[40] Meyer Direct, Ex. 510, Pages 19-20, Lines 10-19, 1-5.

[41] Adams Direct, Ex. 8, Pages 1-2, Lines 12-23, 1-4.

37.88 days associated with Federal Income Tax expense.[42]

4. Ameren Missouri employs statutory tax rates and payment dates when calculating its income tax expense for revenue requirement purposes. As such, there would still be an income tax component of the cash working capital requirement regardless of whether a tax expense was actually incurred or paid.[43]

5. No party challenged Ameren Missouri's calculation of the lead associated with income tax expense. Rather, MIEC's witness asserted that no allowance should be made in cash working capital for income taxes if no cash will be paid out for income taxes.[44]

6. Ameren Missouri's witness agreed that any company activity that does not represent a cash inflow or outflow should not be included in a lead-lag study.[45]

7. Staff's witness on cash working capital never addressed the income tax component. However, Staff supports Ameren Missouri's position on this issue.[46]

8. MIEC's witness on this issue was Greg Meyer. Meyer is also a consultant on public utility regulation and is an associate with Brubaker and Associates, Inc. He has a Bachelor of Science degree in business administration, with a major in accounting, from the University of Missouri. He was also a long-time employee of this Commission before becoming a consultant in 2008.[47]

9. MIEC's witness never quantified the amount of his proposed adjustment regarding income taxes and cash working capital in his testimony. Only in its reply brief

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[42] Adams Rebuttal, Ex. 9, Page 22, Lines 13-16.

[43] Adams Rebuttal, Ex. 9, Pages 22-23, Lines 22-23, 1-3.

[44] Transcript, Page 493, Lines 13-25.

[45] Transcript, Page 452, Lines 10-15.

[46] Staff's Revised Statement of Positions on the Issues, filed October 3, 2012, Page 3.

[47] Meyer Direct, Ex. 510, Appendix A, Page 1, Lines 9-12.

does MIEC point to an accounting schedule attached to Ameren Missouri's true-up direct testimony to claim that $2.6 million in cash working capital for income tax should be removed from rate base for cash working capital.[48]

10. MIEC's witness did not specifically challenge Ameren Missouri's calculation of its income taxes for cash working capital purposes as those taxes are laid out in Ameren Missouri's true-up accounting schedules. Instead, he broadly asserts that "Ameren Corporation has paid little or no income tax in recent years."[49] Similarly, in his surrebuttal testimony he asserts:

> [D]ue to the fact that Ameren Missouri is able to take advantage of significant tax deductions, most, if not all, of its income tax expense represents deferred amounts that are not paid currently. As a result, this expense does not require cash and should not be considered in calculating the CWC requirement.[50]

Conclusions of Law:

A. Any decision by the Commission must be supported by competent and substantial evidence upon the whole record.[51]

Decision:

This is an underdeveloped issue that comes down to a question of witness credibility. MIEC's witness, Greg Meyer, while generally credible on accounting and regulatory issues, claims no special expertise on income tax questions. Yet, he asserts, in very broad terms, his belief that Ameren Corporation has "paid little or no income tax in recent years" and that "most, if not all, of its income tax expense represents deferred

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[48] Reply Brief of The Missouri Industrial Energy Consumers, Page 12. The brief cites to Weiss True-Up Direct, Ex. 78, Schedule GSW-TE 19-1.

[49] Meyer Direct, Ex. 510, Page 19, Line 17.

[50] Meyer Surrebuttal, Ex. 511, Page 22, Lines 11-16.

[51] Section 536.140.2(3), RSMo (Supp. 2011).

amounts that are not paid currently". Meyer did not attempt to calculate any actual figures on what income tax liability and cash payments Ameren Corporation would incur. The witness' vague and unsupported statements about "little or no" or "most, if not all" do not constitute competent and substantial evidence to support MIEC's position. In sum, the Commission finds Greg Meyer's testimony about Ameren Corporation's income tax liability to be not credible.

The credible testimony of Ameren Missouri's witness Michael Adams, and the credible accounting schedules sponsored by Ameren Missouri's witness, Gary Weiss, are sufficient competent and substantial evidence to support Ameren Missouri's position. The Commission finds that the income tax calculation should not be removed from Ameren Missouri's cash working capital requirement.

3. Income Tax & ADIT & NOL:

A. Should a portion of the $2.8 million income tax benefit realized on dividends paid on Ameren Corporation shares held in Employee Stock Ownership Plan ("ESOP") accounts be a reduction to Ameren Missouri's revenue requirement?

Findings of Fact:

1. Ameren Corporation, Ameren Missouri's corporate parent, maintains an employee stock ownership plan (ESOP) as one of a number of tax-qualified employee plans. The ESOP is offered as part of Ameren's 401(k) plan and all employees of Ameren, including employees of Ameren Missouri are eligible to participate.[52]

2. Each year, eligible Ameren employees may designate a limited percentage of their salary to be withheld and contributed to the Ameren 401(k) plan. The corporate employer, be it Ameren Missouri or some other Ameren affiliate, will then match a

[52] Warren Rebuttal, Ex. 10, Page 4, Lines 5-13.

percentage of the employee contribution and add it to the employee's 401(k).[53]

3. Ameren Missouri's cost to pay employee salaries and its share of the corporate match contributed to an employee's 401(k) plan is included in the company's cost of service and is recovered from ratepayers through rates.[54]

4. Ameren Corporation receives certain tax deductions from the federal government for employee salaries and for the match it contributes to the 401(k) to encourage it to offer a 401(k) plan to its employees. Those tax benefits are flowed back to ratepayers and are not in dispute.[55] Rather, the dispute arises from one particular 401(k) related tax deduction received by Ameren Corporation. Ameren Missouri contends that tax deduction belongs entirely to Ameren Corporation. Staff and MIEC claim that a proportionate share of the tax deduction should be included as an offset to the costs included in Ameren Missouri's cost of service for ratemaking purposes. Approximately $3.2 million is at issue.

5. As part of its 401(k) plan, each year an eligible Ameren employee may select one of twenty-one investment funds in which his or her contribution and the employer match will be invested. One of the available investment funds is the Ameren ESOP. Thus, each employee can decide to invest none, some, or all of his or her contribution, including the match, in Ameren stock.[56]

6. The particular tax deduction in dispute is a provision of the federal tax code that allows a corporation to take a Dividends Paid Deduction for a dividend it pays on its

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[53] Warren Rebuttal, Ex. 10, Page 4, Lines 15-17.

[54] Brosch Surrebuttal, Ex. 502, Pages 23-24, Lines 23-24, 1.

[55] Warren Rebuttal, Ex. 10, Page 6, Lines 5-10.

[56] Warren Rebuttal, Ex. 10, Page 4, Lines 15-23.

stock to the extent that stock is held in an ESOP.[57] Ameren Corporation from time to time pays dividends on its stock, including stock held in an ESOP. It is a portion of that ESOP–related tax deduction that Staff and MIEC seek to claim on behalf of Ameren Missouri's ratepayers.

7. MIEC contends that the money Ameren Corporation uses to pay dividends is derived in large part from dividends paid by Ameren Missouri to its corporate parent. The argument is that since Ameren Missouri earns those dividends from rates paid by ratepayers, it is only fair that a portion of the tax benefits derived from those dividend payments should flow back to Ameren Missouri's ratepayers.[58]

8. Staff reaches the same result by arguing that a significant portion of the stock held in the ESOP is the result of contributions made by Ameren Missouri employees. In addition, Staff argues that those employees' salaries, as well as the match contributed by the company, are paid by ratepayers.[59]

9. Neither argument put forth by Staff and MIEC is well founded. Ameren Corporation pays its dividends out of its retained earnings at the sole discretion of its Board of Directors. Some of the money in its retained earnings may have ultimately been derived from money collected from ratepayers for the sale of electricity, but Ameren Corporation could just as easily use funds derived from one of its other subsidiaries to pay a dividend. It could, if it wished, even borrow the money to pay a dividend.[60]

10. The important fact is that retained earnings belong to the company and its

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[57] Warren Rebuttal, Ex. 10, Page 5, Lines 11-15.

[58] Brosch Direct, Ex. 500, Page 29, Lines 5-23.

[59] Cassidy Surrebuttal, Ex. 234, Page 9, Lines 15-20.

[60] Warren Rebuttal, Ex. 10, Page 8, Lines 3-9.

shareholders, not to ratepayers. Ameren Corporation can do whatever it wants with its retained earnings. If it chooses to use those earnings to declare a dividend to its shareholders, it may do so. If it chooses to use those retained earnings to throw a giant party or invest in property on the moon, it must answer only to its shareholders, not to this Commission, and not to ratepayers. Ameren Corporation and its shareholders are entitled to keep any tax benefits that arise from its decision on how to spend its money.

11. The argument that ratepayers have a claim to Ameren Corporation's tax deduction because the stock is purchased by Ameren Missouri's employees whose compensation is paid by ratepayers is even more ill founded. Once salary is paid to an Ameren Missouri employee, it becomes the property of the employee. If that employee chooses to invest part of his or her money in shares of Ameren Corporation, Ameren Missouri's ratepayers do not have any claim to that investment or any tax benefits that may result from that investment. This argument really is as invalid as an argument that the state should be able to claim the mortgage tax deduction of a state employee because the state employee used his or her taxpayer-funded salary to buy the house.

12. Staff and MIEC complain that Ameren Corporation is trying to deny ratepayers their share of the tax benefits derived from the payment of these dividends by hiding behind the corporate distinctions between parent and subsidiary company. However, this argument misses the point. The results would be the same if Ameren Missouri were a stand-alone company paying the dividends directly instead of first contributing the money to its corporate parent. Either way, the dividends are paid from shareholder-owned funds to which ratepayers have no claim.

13. Furthermore, the tax deduction Ameren Corporation receives when it offers a

dividend on stock held by an ESOP is presumably offered to increase the company's incentive to offer that benefit to its employees. Attempting to grab that incentive for Ameren Missouri's ratepayers could only reduce Ameren Corporation's incentive to offer that benefit to Ameren Missouri's employees, to the detriment of those employees.

Conclusions of Law:

A. The law in Missouri is crystal-clear: "When the established rate of a utility has been followed, the amount so collected becomes the property of the utility, of which it cannot be deprived by either legislative or judicial action without violating the due process provisions of the state and federal constitutions."[61] Once Ameren Missouri has earned and retained a profit, ratepayers no longer have a claim to those earnings, whether they are passed to a parent corporation in the form of dividends or spent or invested in some other way by the company.

Decision:

Ameren Missouri ratepayers are not entitled to claim a share of the tax benefits resulting from Ameren Corporation's decision to pay a dividend to Ameren Missouri employees who also happen to be shareholders under Ameren Corporation's ESOP. No portion of the income tax benefit realized on dividends paid on Ameren Corporation shares held in Employee Stock Ownership Plan ("ESOP") accounts should be a reduction to Ameren Missouri's revenue requirement

B. Should CWIP-related ADIT balances be included as an offset to rate base?

Findings of Fact:

[61] *Straube v. Bowling Green Gas Co*., 360 Mo. 132, 142, 227 S.W.2d 666, 671 (Mo. 1950)

1. Federal tax law allows Ameren Missouri to utilize accelerated and bonus depreciation and other means to effectively defer the payment of income taxes associated with construction projects. Because of differences between tax accounting and regulatory accounting, Ameren Missouri is able to collect money from ratepayers to cover those taxes before it must actually pay the taxes. Such deferred taxes are accumulated in Accumulated Deferred Income Tax (ADIT) accounts.[62]

2. The type of ADIT at issue in this case is created when tax law allows a utility to deduct costs associated with a construction project that, under financial and regulatory accounting rules, must be capitalized and depreciated over a period of time.[63]

3. Because the tax benefits resulting from deferred income taxes are not immediately flowed through to ratepayers, credit ADIT balances represent an essentially free source of capital funds available for use by the utility. In other words, that credit ADIT balance would be a free loan to the company from ratepayers. [64]

4. Credit ADIT balances have grown significantly in recent years because, Congress has added a number of deductions and bonus depreciation features to the tax code to help stimulate the economy.[65]

5. Because the credit ADIT balance would otherwise only benefit shareholders, those balances are usually subtracted from the utility's rate base when calculating the company's rates. By that means, the net amount of investor-supplied capital within the

[62] Brosch Direct, Ex. 500, Pages 30-31.

[63] Warren Rebuttal, Ex. 10, Page 11, Lines 13-15.

[64] Brosch Direct, Ex. 500, Page 32, Lines 3-17.

[65] Transcript, Pages 803-804, Lines 24-25, 1-6.

company's rate base can be quantified.[66]

6. Ameren Missouri does not disagree with the general principle to use credit ADIT balances as an off-set to rate base. However, disagreement arises over the treatment of that portion of the ADIT balance related to construction costs incurred for projects that remain in construction work in progress (CWIP) accounts at the end of the test period.[67]

7. Construction work in progress, or CWIP, is treated differently because of a voter-approved initiative that created a statutory prohibition on the inclusion of CWIP in an electric utility's rate base. Ameren Missouri contends that since it is prohibited from including CWIP in its rate base, it should not be required to recognize tax benefits associated with the CWIP as a reduction in rate base until the CWIP itself is added to rate base.[68]

8. Ameren Missouri has removed CWIP related ADIT balances from its rate base in previous rate cases. It explains that it has taken a different position in this case because those balances only became significant in recent years.[69]

9. Even though Ameren Missouri cannot add CWIP to its rate base, and therefore cannot earn a return on that investment, until the property is fully operational and used for service, it is allowed to earn an Allowance for Funds Used for Construction (AFUDC) before the property under construction is added to rate base. AFUDC is accrued during the process of construction and is added to the balances of plant in service that is

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[66] Brosch Direct, Page 32, Lines 15-17.

[67] Warren Rebuttal, Ex. 10, Page 12, Lines 2-4.

[68] Warren Rebuttal, Ex. 10, Page 12, Lines 5-14.

[69] Warren Rebuttal, Ex. 10, Page 13, Lines 10-14.

included in rate base when the plant is placed in service. It is then recovered from ratepayers over the remaining life of the property.[70]

10. Ameren Missouri contends that since current customers are not burdened with CWIP, they should not be allowed to benefit from lower rates that would result from including CWIP-related ADIT balances as an offset to rate base. To do otherwise would benefit current customers at the expense of future customers.[71] However, any "generational" mismatch will be slight. Ameren Missouri will begin recovering nearly all of these AFUDC amounts in its next rate case because all of Ameren Missouri's CWIP projects that were active at the end of the true-up period on July 31, 2012, are estimated to be in service on or before July 31, 2013.[72]

11. CWIP related ADIT balances must be accounted for in rate base because AFUDC is applied to Ameren Missouri's gross investment in CWIP, with no recognition given to the CWIP-related ADIT amounts that serve to reduce the company's actual net capital requirements for CWIP.[73] An example offered by MIEC's witness illustrates this problem:

> Consider a simplified example, where a utility is assumed to be constructing a single asset costing $1 million over a construction period of one year that will be funded fully at the beginning of construction, but will remain in CWIP and earning AFUDC at an assumed 10 percent rate throughout the year of construction. Assume also that the utility has elected 'repairs' tax accounting for this asset, allowing the full cost of the asset to be immediately deducted for income tax purposes in the current tax year. The value of the income tax deduction for this project being treated as a deductible 'repair' at a 38 percent federal/state tax rate would result in an immediate $380,000 income tax deferral to the utility, requiring the accrual of

[70] Brosch Surrebuttal, Ex. 502, Page 29, Lines 8-13.

[71] Warren Rebuttal, Ex. 10, Page 12, Lines 7-14.

[72] Brosch Surrebuttal, Ex. 502, Page 27, Lines 10-12.

[73] Brosch Direct, Ex. 500, Page 37, Lines 8-12.

> CWIP-related ADIT that reduces the utility's actual out-of-pocket investment in the new asset to only $620,000 after taxes.
>
> However, AFUDC will be accrued at 10 percent on the gross CWIP cost for the full year the asset is in CWIP, resulting in Plant-in-Service added to rate base of $1.1 million ($1 million plus $100,000 of AFUDC) with no recognition given to the CWIP-related ADIT in accruing AFUDC. Clearly, when the AFUDC rate is applied to the entire $1 million of gross investment, with no reduction for CWIP-related AFUDC, the utility is fully compensated for its gross investment in this asset. In this example, the $100,000 of allowed AFUDC on a gross $1 million investment, when the utility's after-tax net investment is only $620,000, would significantly overstate AFUDC and future rate base.[74]

In other words, failure to recognize the CWIP-related ADIT balance in the company's rate base will overstate the companies AFUDC costs and future rate base, essentially allowing the company to earn AFUDC and a return on capital supplied by ratepayers.

Conclusions of Law:

A. Missouri's Anti-CWIP statute states:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited.[75]

Decision:

As fully explained in the findings of fact, Ameren Missouri must include CWIP-related ADIT balances as an offset to rate base to avoid overstating AFUDC and future rate base, to the detriment of both current and future ratepayers.

4. Plant in Service Accounting (PISA): Should the Commission grant Ameren Missouri accounting authority to accrue a return on invested capital and to defer depreciation for non-revenue-producing plant additions in a regulatory asset during the period between the date when those plant additions begin serving

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[74] Brosch Direct, Ex. 500, Pages 37-38, Lines 13-25, 1-7.

[75] Section 393.135, RSMo 2000.

customers until the date they are reflected in rate base in a later rate case?

Findings of Fact:

1. This issue is closely tied to Ameren Missouri's frequently repeated concerns about its inability to earn its allowed rate of return due to what it believes to be excessive regulatory lag.[76] The regulatory lag that plant in service accounting (PISA) aims to address results from the regulatory treatment of newly constructed plant. While the plant is being constructed, the utility is able to accrue AFUDC to compensate it for the money that is being invested in the plant. That money cannot be added directly into rate base because of Missouri's anti-CWIP statute. The AFUDC is accumulated during the construction process and is moved into rate base when the plant goes into service. The utility recovers that AFUDC cost over the remaining service life of the plant.[77]

2. AFUDC stops when the plant goes into service. At that point, the cost of the plant is eligible to be included in rate base and the plant begins depreciating. However, the utility cannot begin to recover the cost of the plant in rates until that cost is added to rate base in a subsequent rate case. There will always be some gap after AFUDC stops and before the cost of the plant can be put into rate base.[78] It is that gap that Ameren Missouri seeks to bridge through its PISA proposal.

3. PISA is a new concept developed by Ameren Missouri's Vice President, Business Planning and Controller, Lynn Barnes.[79] Since it is a new concept, it has not

[76] Barnes Rebuttal, Ex. 12, Page 18, Lines 6-9.

[77] Barnes Rebuttal, Ex. 12, Page 20, Lines 4-11.

[78] Barnes Rebuttal, Ex. 12, Page 20, Lines 12-17.

[79] Transcript, Page 582, Lines 2-4.

been adopted by any other state utility commission.[80] The PISA proposal would only apply to the net change in plant in service that is unrelated to new business. In other words, it would not apply to new service connections that would generate new revenue for the company.[81]

4. In effect, PISA would allow Ameren Missouri to continue to accrue AFUDC on eligible plant additions until that new plant can be added to the company's rate base in a future rate case. In that, it is very similar to the well-known regulatory concept of construction accounting.

5. Construction accounting is frequently used to help a utility recover the cost of single large construction projects, such as Ameren Missouri's recent Sioux Scrubber project. Through PISA, Ameren Missouri would extend that principle of cost recovery to include the many small construction projects that do not produce new revenue for the company, but collectively tie up a large amount of the company's capital outlays.[82]

6. There are several problems with Ameren Missouri's PISA proposal. First, over time, PISA could place a very heavy financial burden on ratepayers. Adoption of PISA would have no impact on the rates established for this case because the proposal is only to allow Ameren Missouri to begin to defer certain costs for possible recovery in a future rate case. However, if the Commission allows Ameren Missouri to recover the deferred costs in its next rate case there would be an impact on rates at that time.[83]

7. If PISA had been implemented in the last rate case, $637 million in plant

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[80] Transcript, Page 580, Lines 17-21.

[81] Barnes Direct, Ex. 11, Page 18, Lines 4-12.

[82] Barnes Rebuttal, Ex. 12, Page 21, Lines 3-13.

[83] Transcript, Page 607, Lines 17-23.

additions would have qualified for PISA treatment during the period between the true-up date in the company's last rate case and the true-up date in this case. Lost depreciation and return that would be included in rate base under the PISA proposal amounted to $37.6 million during that period. If PISA had been in effect for this rate case, the company's annual revenue requirement would have been increased by $6.2 million.[84]

8. Although PISA would have an initial impact of around $6.2 million per year in the next rate case, those costs would not end after one year. The additional revenue Ameren Missouri would recover through PISA would continue to accumulate throughout the 30-40 year life of the assets as they depreciate.[85] Over forty years, that $6.2 million per year would total more than $240 million.[86] Of course, the PISA would not necessarily end after a single rate case. If the Commission renewed PISA for additional years, additional recoveries would tend to pancake on top of each other and the numbers could quickly become very large.

9. Second, because PISA is a new concept that has never been tested, there are no clear standards for what would be treated as a non-revenue producing asset that should be excluded from the PISA.[87] Instead, the Commission's Staff would have to sort through all the company's data to determine whether the company has properly classified those assets.[88] The burden on Staff to review company information in rate cases is already substantial.

10. Third, PISA would violate the test-year principle in that it would routinely draw

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[84] Barnes Surrebuttal, Ex. 13, Pages 5-6, Lines 21-23, 1-5.

[85] Transcript, Page 669-670, Lines 7-25, 1-16.

[86] Transcript, Page 675, Lines 2-4.

[87] Brosch Direct, Ex. 500, Pages 21-22, Lines 17-23, 1-4.

[88] Transcript, Pages 743-744.

non-test year expenses into the test year for the next rate case. The test year principle is important because it is designed to match revenues and expenses at a given time to try to determine an appropriate revenue requirement for the company.[89] By drawing in certain out-of-test-year expenses to be matched against test year revenues, while not examining all factors that might demonstrate a corresponding increase in revenue or decrease in expenses, PISA would unfairly increase the company's revenue requirement at the expense of ratepayers.[90]

11. The Commission does on occasion authorize accounting authority orders and tracking mechanisms that allow a utility to defer certain extraordinary costs for possible recovery in a future rate case. Several such mechanisms are authorized in this case. In addition, the Commission has authorized the use of construction accounting to help utilities deal with the financial burden of large construction projects. However, those mechanisms are premised on the existence of some extraordinary circumstance. Ameren Missouri concedes the expenses it would recover through PISA are not extraordinary, are not volatile or unpredictable, and are not outside the company's control. [91]

12. Fourth, Ameren Missouri contends PISA is needed to provide the company with a greater incentive to invest limited capital in needed infrastructure repairs and replacement.[92] However, while Ameren Missouri's witness testified that there are some additional discretionary capital projects the company might like to undertake if it were allowed PISA, it did not demonstrate that there is any great un-met need for additional

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[89] Robertson Direct, Ex. 406, Page 6, Lines 3-6.

[90] Brosch Direct, Ex. 500, Pages19-20, Lines 15-22, 1-12.

[91] Transcript, Page 656-657, Lines 18-23, 1-20.

[92] Barnes Direct, Ex. 11, Page 19, Lines 6-16.

capital investment to ensure delivery of safe and adequate service.[93] Indeed, there is reason to be concerned that PISA would encourage Ameren Missouri to undertake capital projects that, while helpful, are not necessary to provide safe and adequate service, thereby unnecessarily driving up rates.

13. Finally, PISA seems to be a solution in search of a problem. Ameren Missouri has had difficulty earning its allowed ROE in the past several years. The company likes to blame that failure on systemic problems in Missouri's regulatory scheme that lead to excessive regulatory lag.[94] However, many businesses and individuals have been unable to earn as much as they might like in the economic conditions prevailing in recent years.

14. Furthermore, utility ratemaking is forward looking, concerned with current and anticipated financial conditions. What the company has earned in the past does not necessarily tell us what it will be able to earn in this future.[95] In the past several rate cases, the Commission has implemented several trackers and other regulatory measures that should enhance Ameren Missouri's ability to earn its allowed rate of return. Those previous measures should be allowed an opportunity to work before further measures are undertaken.

15. Indeed, a surveillance report that Ameren Missouri supplied to Staff showed that for the 12 months ended June 30, 2012, within the true-up period for this case, Ameren Missouri's actual earned return on equity was 10.53 percent, which is above the 10.2 percent return on equity allowed in its last rate case.[96] Ameren Missouri attempted to

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[93] Transcript, Pages 699-700.

[94] Baxter Direct, Page 14, Lines 2-4.

[95] Brosch Direct, Ex. 500,Page 9, Lines 5-9.

[96] Exhibit 237.

dismiss that 10.53 percent return as being attributable to warmer than normal weather and to other anomalies, but there it is. Under the circumstances, it is not clear that there is a systemic problem that needs to be solved with PISA.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

After considering Ameren Missouri's PISA proposal, the Commission finds that PISA would be bad public policy and should not be authorized.

5. Rate Case Expense: What is the appropriate amount to include in Ameren Missouri's revenue requirement for rate case expense?

Findings of Fact:

1. Rate case expense is the amount Ameren Missouri has spent to present and defend its rate increase request before the Commission. Ameren Missouri incurs such costs to procure expert testimony and to pay its lawyers to present that testimony.

2. Ameren Missouri estimates it will spend $1,903,000 for rate case expense in this case.[97] That number is necessarily an estimate because most rate case expenses are incurred in conjunction with the hearing, which, of course, occurs after the true-up date of July 31, 2012. Indeed, the actual final cost figures will not be known until after this report and order is issued.[98]

3. Ameren Missouri proposes to calculate the amount of rate case expense to be included in rates by averaging the actual rate case expenses from the company's two prior rate cases with its estimate of expenses for this case. Rate case expense for File No.

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[97] Weiss Direct, Ex. 5, Page 28, Lines 7-8.

[98] Transcript, Pages 862-863, Lines 2-25, 1-12.

ER-2010-0036 was $2,128,352, for File No. ER-2011-0028 it was $1,735,867, and the estimated of expenses for this case is $1,903,000. Adding those three numbers and dividing by three results in an average of $1,922,000. Since, on average Ameren Missouri has filed a new rate case every 15 months, Ameren Missouri would divide that number by 15, multiply it by 12, to reach a normalized rate case expense of $1,538,000. That is the amount Ameren Missouri proposes to include in its annual cost of service for calculation of rates in this case.[99]

4. Staff's witness, Lisa Hanneken, analyzed Ameren Missouri's recent rate cases and proposes that Ameren Missouri be allowed to $1 million in its annual cost of service for rate case expense. That amount assumes a total rate case expense of $1.5 million, which is then normalized on an assumption that Ameren Missouri will file its next rate case in 18 months. ($1,500,000 divided by 18 months, multiplied by 12 months = $1,000,000).

5. Public Counsel proposes a sharp departure from prior Commission treatment of rate case expense. First, it proposes that the Commission disallow as imprudent all the money Ameren Missouri has spent to hire outside consultants and lawyers.[100] Second, for expenses not disallowed, Public Counsel proposes the Commission allow Ameren Missouri to recover only half from ratepayers, with the remainder to be imposed on shareholders. Specifically, after disallowing all cost of outside consultants and lawyers, Public Counsel would allow Ameren Missouri to recover $2,327[101], annualized over 15 months.[102] That

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[99] Barnes Rebuttal, Ex. 12, Page 30, Lines 6-19.

[100] Robertson Direct, Ex. 406, Pages 28-29, Lines 20-21, 1-12.

[101] Robertson True-Up Direct, Ex. 411, Page 3, Lines 10-12.

[102] Robertson Direct, Exhibit 406, Page 31, Lines 16-20.

amounts to $1,861.60 to be included in the cost of service for this case.

6. Public Counsel contends Ameren Missouri's use of outside consultants and attorneys to prepare and prosecute its rate case is imprudent. Public Counsel argues the company has "a large number of accountants, engineers, and others that that presumably could have been utilized to prepare, file and defend its rate increase request."[103] Public Counsel alleges Ameren Missouri therefore acted imprudently by hiring two outside legal firms and three outside consultants to develop and present significant portions of its case.[104]

7. Public Counsel assumes that since Ameren Missouri has many full-time employees with college degrees in relevant fields, those employees, with their relevant work experience, should be able to perform the work required to prepare and present a rate case to the Commission.[105] However, Public Counsel never performed any analysis of specific Ameren employees to determine if they would have any particular expertise or the time available from their regular duties to participate in the rate case.[106]

8. Much of the testimony offered in this case came from witnesses who were full-time Ameren employees, and much of that testimony was presented and defended by the two in-house attorney employed to represent Ameren Missouri. However, those Ameren Missouri employees have job duties in running the company that limit their availability to present a rate case. Furthermore, Ameren Missouri does not have full-time employees with the detailed, national expertise necessary to address certain policy

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[103] Robertson Direct, Ex. 406, Page 19, Lines 19-21.
[104] Robertson Direct, Ex. 406, Page 20, Line 1.
[105] Robertson Direct, Ex. 406, Page 15, Lines 4-9.
[106] Transcript, Page 926, Lines 17-20.

issues.[107]

9. Ameren Missouri did present testimony from several outside consultants on specific issues. Public Counsel complains that such testimony, specifically that offered by John Reed, James Guest, and James Warren, was duplicative of testimony that was offered by Ameren employees.[108] Having closely examined that testimony during the course of the hearing, the Commission finds that Ameren Missouri's outside witnesses offered detailed expert opinion that appropriately presented Ameren Missouri's positions on the issues. While Ameren employees offered testimony on the same broad issues, that testimony was not duplicative of the testimony offered by the outside experts.

10. The testimony of Mr. Hevert on cost of capital, whose fees Public Counsel would also disallow,[109] is a good illustration of why Ameren Missouri is sometimes justified in hiring outside expert witnesses. As indicated elsewhere in this report and order, the determination of an appropriate return on equity is a very difficult matter that requires a great deal of skill and expertise. There are Ameren employees who understand cost of capital questions, but they are engaged full-time in managing the capital needs of the company.[110] It is unreasonable to expect that Ameren Missouri should be precluded from recovering the cost of hiring an appropriate return on equity expert to counter the experts engaged by the other parties to the case.

11. Aside from its contention that Ameren Missouri was imprudent in hiring outside attorneys and expert witnesses, Public Counsel also contends that ratepayers

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[107] Barnes Rebuttal, Ex. 12, Page 34, Lines 3-20.

[108] Robertson Surrebuttal, Ex. 408, Pages 7-9.

[109] Robertson Direct, Ex. 406, Page 17, Lines 21-23.

[110] Barnes Rebuttal, Ex. 12, Page 34, Lines 16-20.

should not be forced to pay for what it describes as an "elaborate defense of private interests".[111] Public Counsel contends Ameren Missouri has presented an elaborate defense in this case because it hired outside legal counsel and consultant services when the same services could likely have been provided by full-time Ameren employees.[112]

12. Although Public Counsel describes this argument as a separate basis for finding Ameren Missouri's use of non-employees to be imprudent,[113] it is just a restatement of the other prudence argument that the Commission has already rejected.

13. Aside from the prudence arguments, Public Counsel does not contend that the Commission should entirely disallow the company's rate case expense. It concedes that since rate case proceedings are a part of a regulated utility's normal cost of business those costs should be recoverable in rates.[114]

14. However, Public Counsel contends that as a matter of policy, the Commission should require shareholders to pay half of the admittedly prudent costs that Ameren Missouri incurred in prosecuting this rate case because shareholders, as well as ratepayers, benefit from any rate increase that results from this case.[115] Furthermore, Public Counsel suggest that a sharing of costs would provide Ameren Missouri with an incentive to control what it describes as a rising level of rate case expense.[116]

15. However, there is no "rising level of rate case expense". Ameren Missouri's estimated level of rate case expense for this case is in line with the amounts of rate case

[111] Robertson Direct, Ex. 406, Page 23, Lines 7-11.
[112] Robertson Direct, Ex. 406, Page 24, Lines 9-13.
[113] Robertson Direct, Ex. 406, Page 29, Lines 9-12.
[114] Robertson Direct, Ex. 406, Page 11, Lines 17-21.
[115] Robertson Direct, Ex. 406, Page 11, Lines 1-7.
[116] Robertson Direct, Ex. 406, Page 14, Line 14.

expense it has incurred in its last two rate cases.[117] Indeed, Staff premised its recommended level of allowed rate case expense on a perceived downward trend in rate case expense.[118]

16. Rate case expense is just another cost of doing business for a regulated utility. As a regulated utility, Ameren Missouri has a legal obligation to provide safe, adequate, and reliable service to ratepayers. Because it is a regulated utility, the only way Ameren Missouri can raise its rates to charge what this Commission determines to be just and reasonable is through the rate case process. The rate case process is adversarial, just as is any other civil litigation in this country. That means all parties, including the company, must be able to present their facts and arguments so the Commission can reach a proper and fair resolution.

17. Shareholders benefit when rates go up to a just and reasonable level, but so do ratepayers. Shareholders may receive higher dividends and benefit from higher stock prices, but ratepayers receive the benefit of safe, adequate, and reliable service. No one benefits when a utility is deprived of the ability to charge its customers a just and reasonable rate.

18. Staff does not propose that any part of Ameren Missouri's rate case expense be disallowed as imprudent,[119] nor does it advocate for the sharing of costs between shareholders and ratepayers.[120] Instead, Staff looked at historical data regarding Ameren Missouri's actual rate case expenses and discerned a downward trend in those expenses.

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[117] Barnes Rebuttal, Ex. 12, Page 30, Lines 6-8.

[118] Hanneken Surrebuttal, Ex. 236, Page 7, Lines 20-22.

[119] Transcript, Pages 912-913, Lines 24-25, 1-2.

[120] Transcript, Page 879, Lines 17-20.

Staff also concluded that Ameren Missouri tended to overestimate its expenses. Based on that information, Staff estimated the company's rate case expense for this case to be $1.5 million. Staff assumed the company would file its next rate case in 18 months and therefore normalized that $1.5 million to allow Ameren Missouri to recover $1 million per year for rate case expense.[121]

19. The problem with Staff's estimate of $1.5 million as Ameren Missouri's rate case expense for this case is that it seems to be little more than an educated guess based on past rate case expenses. Staff's witness did not compare the number of issues in this case with earlier cases, she did not compare the total number of witnesses in this case with earlier cases, she did not compare the number of outside consultants or the number of intervenors in this case with earlier cases, nor did she use any mathematical calculation to arrive at her cost estimate.[122] In sum, Staff's general cost estimate is less reasonable than the specific cost estimate offered by Ameren Missouri.

Conclusions of Law:

A. The Commission established its standard for determining the prudence of a utility's expenditures in a 1985 decision regarding Union Electric's construction of the Callaway nuclear plant. In that decision, the Commission held that a utility's expenditures are presumed to be prudently incurred, but, if some other participant in the proceeding creates a serious doubt as to the prudence of the expenditure, then the utility has the

[121] Hanneken Surrebuttal, Ex. 236, Pages 7-8, Lines 13-24, 1-4.

[122] Transcript, Pages 909-910, Lines 3-25, 1-17.

burden of dispelling those doubts and proving the questioned expenditure to have been prudent.[123]

B. The Commission's use of that prudence standard has been upheld by reviewing courts in numerous cases.[124]

C. The Commission's prudence standard applies to Ameren Missouri's expenditures for rate case expense just as it would apply to any other expense that the Commission is reviewing in this case.

D. Based on the facts as set forth in its Finding of Fact for this issue, the Commission concludes that Public Counsel has failed to present sufficient evidence to create a serious doubt regarding the prudence of Ameren Missouri's decision to engage the services of outside expert consultants and legal counsel for the presentation of this rate case. Therefore, those costs are presumed to be prudently incurred.

Decision:

Ameren Missouri's estimate of rate case expense for this case is reasonable and Ameren Missouri's cost of service for this case shall include an annualized rate case expense of $1,538,000. The Commission has opened File No. AW-2011-0330 as a separate investigative case to examine the question of rate case expense in a more general manner. The Commission will renew its efforts to proceed with that investigation.

6. Property Tax Refund: What portion, if any, of the $2.9 million property

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[123] *In the matter of the determination of in-service criteria for the Union Electric Company's Callaway Nuclear Plant and Callaway rate base and related issues. And In the matter of Union Electric Company of St. Louis, Missouri, for authority to file tariffs increasing rates for electric service provided to customers in the Missouri service area of the company.* 27 Mo. P.S.C. (N.S.) 183, 193 (1985).

[124] For example see, *State ex rel. Assoc. Natural Gas Co. v. Public Serv. Com'n*, 954 S.W.2d 520 (Mo. App. W.D. 1977).

tax refund received by Ameren Missouri should be credited to ratepayers? If an amount should be credited, over what period should the credit be amortized?

Findings of Fact:

1. In the Report and Order that resolved Ameren Missouri's last rate case, ER-2011-0028, the Commission set rates that allowed Ameren Missouri to recover roughly $129 million for payment of property taxes. That amount was based on the $119 million Ameren Missouri paid for property taxes in 2010, with an additional $10 million allowed for the anticipated payment of property taxes associated with the Sioux Scrubber and Taum Sauk construction projects that were being taxed for the first time in 2011.[125]

2. While that rate case was pending, Ameren Missouri was in the process of appealing approximately $29 million of its 2010 property tax liability to the Missouri State Tax Commission. Consequently, at the time rates were set, no one knew whether Ameren Missouri would be able to obtain a refund of all or part of the $29 million tax payment that was under appeal.

3. To deal with the uncertainty of the possible $29 million tax refund, the Commission's report and order found that Ameren Missouri had agreed to track any tax refund it might receive. Ameren Missouri's witness in this case confirms that the company agreed to track any tax refund.[126]

4. In its 2011 report and order, the Commission declined to order Ameren Missouri to return to its customers any tax refund it might receive as a result of its tax appeal. The Commission reasoned that it could not bind a future Commission and must

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[125] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order, Issued July 13, 2011, Pages 105-109.

[126] Transcript, Page 973, Lines 10-11.

leave the decision about how such tax refund should be handled to a future rate case.[127]

However, the Commission stated:

> If Ameren Missouri does receive a tax refund, then the Commission would certainly expect that the company would return that refund to its customers who are ultimately paying the tax bill. It is hard to imagine any circumstance in which such a refund would not be ordered. However, such an order must wait until a future rate case in which that decision will be presented to the Commission.[128]

This is now the future rate case and the Commission must decide how the tax refund should be handled.

5. Late in the summer of 2011, after the Commission issued its report and order in the 2011 rate case, Ameren Missouri reached a settlement with the State Tax Commission by which it received tax refunds totaling $2.9 million.[129]

6. Staff and MIEC contend the $2.9 million tax refund should be returned to ratepayers through a two-year amortization, beginning with the effective date of rates established by this order.[130]

7. Although the rates established in the 2011 rate case allowed Ameren Missouri to recover an amount equal to all its 2010 tax liability, including the $2.9 million the company recovered as a tax refund, those rates did not necessarily allow the company to recover all it paid for property taxes in 2011. Tax liability may go up or down from year to

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[127] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order, Issued July 13, 2011, Page 111.

[128] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order, Issued July 13, 2011, Page 110.

[129] Weiss Rebuttal, Ex. 6, Page 27, Lines 18-21.

[130] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 117, Lines 20-25. Meyer Direct, Ex. 510, Page 17, Lines 1-7.

year and rates are not changed to reflect the new tax amounts until the company files a new rate case.[131] Ordinarily that variation is simply treated as an element of regulatory lag and no adjustment is made to account for the variations.

8. However, this is a unique situation. In the previous rate case, the Commission set rates based on the assumption that Ameren Missouri would pay the full amount of taxes for which it had been billed, even though the company was appealing $29 million of that tax bill. The Commission might have set Ameren Missouri's rates as much as $29 million lower than it did on the assumption that Ameren Missouri would prevail on its tax appeal. However, the Commission did not do so based, at least in part, on Ameren Missouri's representation that it would track those costs.

9. Ameren Missouri now contends that when it agreed to track those costs it merely intended to keep track of the property tax refund so it could be identified for the audit in this case.[132]

10. That was not the purpose of tracking the costs that the Commission understood at the time it stated "It is hard to imagine any circumstance in which such a refund would not be ordered.

Conclusions of Law:

There are no additional Conclusions of Law for this issue.

Decision:

The Commission will require Ameren Missouri to comply with the implicit agreement that allowed Ameren Missouri to avoid a possible reduction in rates surrounding its appeal

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[131] Transcript, Pages 984-988. See also, Exhibit 55.

[132] Ameren Missouri's Initial Post-Hearing Brief, Page 103. This explanation was not offered under oath by any witness.

of its 2010 tax liability. Ameren Missouri shall return the $2.9 million tax refund to rate payers, amortized over two years.

7. Property Taxes: What property tax rates should be used in calculating the allowance for property tax expense to be included in Ameren Missouri's revenue requirement?

Findings of Fact:

1. Each year, Ameren Missouri must pay property taxes on the property is owns around the state. All parties agree the company should be able to recover the cost of paying those property taxes from ratepayers as a cost of doing business. The question is, how much should the company be able to recover in rates?

2. Staff and MIEC contend the Commission should base the amount Ameren Missouri is allowed to recover for property taxes on the actual amount of property tax the company paid during the test year. The actual amount Ameren Missouri paid for property taxes during true-up period of the test year, specifically in December 2011, was $127.2 million.[133]

3. Ameren Missouri contends use of the actual property tax paid during the test year would not allow the company to recover the actual amount of property tax it will likely incur going forward, as the tax imposed is likely to increase. Ameren Missouri offers two alternatives for calculation of the amount of property tax it should be allowed to recover in rates. The first alternative would apply the company's actual 2011 tax rates to the actual 2012 certified assessed valuation to arrive at a property tax amount of approximately $128.3 million. The second alternative would assume a tax rate that increases by eleven percent from the actual 2011 tax rates, applied to the actual 2012 certified assessed

[133] Carle Surrebuttal, Ex. 218, Page 8, Lines 20-22.

valuation to arrive at a property tax amount of approximately $130.4 million.[134]

4. The Missouri State Tax Commission is responsible each year to determine the valuation and assessment of the distributable commercial real and personal property of all Missouri utility companies, including Ameren Missouri.[135]

5. The Tax Commission determines the value of utility property as of January 1 of each year. Using the valuation certified by the Tax Commission, each taxing jurisdiction within Ameren Missouri's service territory determines its tax rate and applies that rate to the value of the utility party subject to its jurisdiction. Any of the taxing jurisdictions can choose to raise or lower its tax rate to meet its budgetary needs.[136]

6. After the taxing jurisdictions determine and report their rates, each of the 66 counties in which the company owns property sends a tax bill to Ameren Missouri in November or December. Ameren Missouri will pay its tax bill for 2012 in December 2012.[137]

7. The State Tax Commission certified its valuation of Ameren Missouri's property on June 28, 2012, which is within the true-up period for the test year in this case.[138]

8. Although the valuation of Ameren Missouri's property was certified within the test year, the actual amount of taxes Ameren Missouri will need to pay for 2012 is dependent upon the tax rate established by the myriad taxing authorities within its service territory. Those rates could go up or down and thereby affect Ameren Missouri's total tax

[134] Cudney Rebuttal, Ex. 14, Page 6, Lines 7-23.
[135] Cudney Rebuttal, Ex. 14, Page 3, Lines 1-3.
[136] Cudney Rebuttal, Ex. 14, Page 3, Lines 13-16.
[137] Transcript, Page 1012, Lines 12-22.
[138] Cudney Rebuttal, Ex. 14, Page 3, Lines 10-12.

bill. Ameren Missouri will not know those tax rates until it receives the last tax bill from 66 counties sometime in December.[139]

9. The test year and true-up period for this case ended on July 31, 2012. On December 31, 2011, within that test year and true-up period, Ameren Missouri paid property taxes totaling $127.2 million. That amount is clearly known and measurable.

10. The amount Ameren Missouri will pay in property taxes in December 2012 is not yet known and measurable and falls outside the test year and true-up period for this case.

11. If the Commission were to set Ameren Missouri's rates based on projections about what it might pay in property taxes in December 2012, it would violate an important rate making principle. A December 2012 payment would be outside the test year and true-up period. The test year and true-up period is important because it allows the Commission to set rates while considering the relationship between revenues, expenses and rate base within a specified period. Ameren Missouri is asking the Commission to make an isolated adjustment for taxes paid outside that specified period. By going outside the specified test year and true-up period to make an isolated adjustment, the Commission would necessarily be ignoring other expense and income items that might also change the company's revenue requirement.

12. There are many such out of test year items that might affect the company's revenue requirement. A good example was raised by MIEC. Ameren Missouri refinanced some of its outstanding debt in September 2012 at a lower interest rate, thus saving the

[139] Cudney Rebuttal, Ex. 14, Page 3, Lines 20-21.

company money.[140] Since that transaction is outside the test year and true-up period it has no effect on the rates established in this case. But, if the Commission were to go outside the test year and true-up period to make an isolated adjustment for 2012 tax payments it would need to consider other out of period adjustments to maintain the matching principle of evaluating all relevant factors for that period. Quickly the integrity and relevance of the test year and true-up period would be lost

13. Nevertheless, the Commission sometimes makes isolated adjustment for certain known and measureable costs when doing so is necessary to ensure just and reasonable rates are established. However, Ameren Missouri's 2012 property taxes are not known and measureable and inclusion of those costs is not necessary to establish just and reasonable rates.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall be allowed to recover $127.2 million in rates for property taxes as proposed by Staff and MIEC.

8. Renewable Energy Standard (RES) Costs:

A. Should the Commission order Ameren Missouri to include a base level of RES costs in permanent rates? If so, what is the base amount to include in permanent rates and should the level included in permanent rates in this case be netted against any future deferred expenditures that occur beyond the July 31, 2012, true-up date?

Findings of Fact:

1. Ameren Missouri is required to incur certain costs to comply with Missouri's

[140] Transcript, Page 308, Lines 6-21.

Renewable Energy Standard (RES) law. Thus far, the bulk of the RES costs incurred by the company are for rebate payments made to customers who install their own solar power systems.[141] During the updated test year, Ameren Missouri incurred approximately $4.7 million in such RES costs.[142]

2. Ameren Missouri proposes to recover that $4.7 million amount in its base rates in this case.[143] It would then track its future costs above or below that base amount and establish what would essentially be an AAO to recover or refund any variation from that base amount.[144] Staff supports Ameren Missouri's proposal.[145]

3. MIEC does not take issue with the amount of RES costs Ameren Missouri has incurred. However, it interprets the applicable Commission regulation to preclude the inclusion of any amount of those costs in base rates.[146]

Conclusions of Law:

A. Missouri's statute known as the Renewable Energy Standard is found at Sections 393.1025 and 393.1030, RSMo (Supp. 2011). That law requires Missouri's investor-owned electric utilities, including Ameren Missouri, to meet portfolio standards such that increasing percentages of the electric power sold by the utility are obtained from renewable energy resources. The percentage of power that must be obtained from

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[141] Transcript, Pages 1042-1043, Lines 23-25, 1-3.

[142] Transcript, Pages 1069-1070, Lines 23-25, 1-3.

[143] The exact amount is $4,656,595. Transcript, Page 1073, Line 8.

[144] Transcript, Page 1047, Lines 17-23.

[145] Cassidy Surrebuttal, Ex. 234, Page 6, Lines 18-22.

[146] Meyer Direct, Ex. 510, Page 8, Lines 3-8.

renewable energy resources rises from two percent for 2011 through 2013 to fifteen percent beginning in 2021.[147]

B. Another section of the Renewable Energy Standard requires each investor-owned electric utility, again including Ameren Missouri, to make available to its retail customers a standard rebate offer for new or expanded solar electric systems.[148]

C. The Renewable Energy Standard directs the Commission to make whatever rules are necessary to enforce the renewable energy standard. The statute specifically requires that the Commission's rule include "[p]rovision for recovery outside the context of a regular rate case of prudently incurred costs and the pass-through of benefits to customers of any savings achieved by an electrical corporation in meeting the requirements of this section."[149]

D. The Commission's RES rule is found at 4 CSR 240-20.100. That regulation describes in detail a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM) by which a utility may recover its RES compliance costs outside a rate case. The RESRAM would operate in much the same manner as a fuel adjustment clause to allow periodic rate adjustments between general rate cases.

E. However, the regulation does not require an electric utility to implement a RESRAM to recover its costs. Instead, it states:

> Alternatively, an electric utility may recover RES compliance costs without use of the RESRAM procedure through rates established in a general rate proceeding. In the interim between general rate proceedings the electric utility may defer the costs in a regulatory asset account, and monthly calculate a carrying charge on the balance in the regulatory asset account

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[147] Section 393.1030.1, RSMo (Supp. 2011).

[148] Section 393.1030.3, RSMO (Supp. 2011).

[149] Section 393.1030.2(4).

equal to its short-term cost of borrowing. …[150]

F. Ameren Missouri and Staff interpret this provision of the regulation to allow the company to include a base level of compliance costs in rates and to then track any variation in those costs through an AAO for future recovery in the next rate case. That is the way the Commission handled the matter in the last rate case.[151]

G. MIEC interprets the regulation differently. MIEC would rely more heavily on the second sentence of the provision to argue that if the company does not have a RESRAM, which Ameren Missouri does not, it can only defer all costs in an AAO for recovery in a future rate case. It would not allow Ameren Missouri to establish a cost base within this rate case. [152] Under MIEC's interpretation, Ameren Missouri would likely eventually recover all its costs with interest, but its recovery of those costs would be delayed until it files another rate case.[153]

H. MIEC's interpretation of the regulation is incorrect because it ignores the plain dictate of the first sentence, which simply states that if it chooses not to use a RESRAM, the utility can recover its RES costs through rates established in a general rate case. The second sentence simply established the means by which the utility can track those costs between rate cases without using a RESRAM.

I. The purpose of the regulation is to enable the utility to recover its RES costs and thereby remove barriers to the implementation of renewable energy programs. The interpretation of the regulation espoused by Ameren Missouri and Staff assures that the

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[150] 4 CSR 240-20.100(6)(D).

[151] Transcript, Page 1070, Lines 18-23.

[152] Transcript, Page 1049, Lines 3-11.

[153] Transcript, Page 1054-1055, Lines 15-25, 1-23.

intent of the regulation is met. In contrast, MIEC's interpretation of the regulation would assure that the utility would be unable to recover its RES costs in a timely manner. Instead, it would always be required to delay its recovery of costs until its next rate case. Such a delay would hurt the utility's cash flow and would cause matching problems in that future ratepayers would be required to pay the RES costs incurred by current ratepayers.

Decision:

Ameren Missouri shall include a base level of $4,656,595 for REC compliance costs in the rates established in this case and shall track any variation in those costs through an Accounting Authority Order for future recovery in its next rate case.

B. Over what period of years should the Commission order Ameren Missouri to amortize the deferred RES costs incurred from January 1, 2010, through July 31, 2012?

C. Should the Commission order Ameren Missouri to include the unamortized RES deferred regulatory asset balance from January 1, 2010, through July 31, 2012, in rate base?

Findings of Fact:

1. In Ameren Missouri's last rate case, the Commission handled RES costs in the same manner it found to be appropriate in this case. A base level of RES costs was established at $885,266 and Ameren Missouri was allowed to include additional expenditures in an AAO for consideration in its next rate case.[154]

2. This is the next rate case, and Ameren Missouri has deferred $6.3 million in that AAO. All parties agree on that amount.[155] The Commission must now determine how

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[154] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order issued July 13, 2011, Page 101.

[155] Transcript, Page 1069, Lines 7-22.

Ameren Missouri will be allowed to recover that $6.3 million.

3. Ameren Missouri proposes that it be allowed to amortize and recover that $6.3 million over two years. It also wants to include the unamortized balance in its rate base.[156] Staff proposes to amortize that amount over three years, but would not allow the unamortized balance in rate base.[157] MIEC would amortize the $6.3 million over six years and would allow the unamortized balance to be included in rate base.[158] Staff would also accept MIEC's proposal.[159]

4. The primary item included in Ameren Missouri's RES expense is the cost of paying solar rebates to customers who have installed solar equipment at their home. The customers, not Ameren Missouri, own and operate that solar equipment.[160] Another significant RES cost to Ameren Missouri is their program to purchase Renewable Energy Credits (RECs) to comply with RES requirements.[161] Ameren Missouri's RES costs do not include capital costs, such as the solar equipment Ameren Missouri has installed at its own headquarters.[162]

5. MIEC suggests that a relatively long six-year amortization period is appropriate because the solar equipment for which the rebates are paid has a service life of around ten years.[163] However, because the utility does not own the solar equipment, there is no reason to link the amortization period to the life of the solar equipment. From Ameren

[156] Weiss Rebuttal, Ex. 6, Page 7, Lines 3-4.

[157] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 133, Lines 28-31.

[158] Meyer Surrebuttal, Ex. 511, Page 5, Lines 20-21.

[159] Cassidy Surrebuttal, Ex. 234, Page 7, Lines 9-16.

[160] Transcript, Pages 1042-1043, Lines 23-25, 1-13.

[161] Transcript, Pages 1406-1047, Lines 18-25, 1-3.

[162] Transcript, Page 1047, Lines 4-10.

[163] Meyer Surrebuttal, Ex. 511, Pages 5-6, Lines 22-23, 1-7.

Missouri's perspective, RES costs are simply an expense that should be recovered quickly rather than over the life of the equipment. That suggests a short amortization period is appropriate.

6. Typically, the items the Commission will allow a utility to include in its rate base are investments in plant, fuel inventories and other capital items.[164] Since these RES costs are not capital items and will be amortized over a short period, inclusion of those costs in rate base would not be appropriate.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall recover $6.3 million in past RES costs amortized over three years with the unamortized balance not included in rate base.

9. Coal Inventory, Including Coal-in-Transit: Should the value of Ameren Missouri's coal inventory include the value of coal in transit?

Findings of Fact:

1. Ameren Missouri must purchase massive amounts of coal to be burned in its coal-fired electric generating plants. That coal must be shipped to the generating plants from the coal mines. Ameren Missouri takes title to the coal as it is loaded into Ameren Missouri's railcars at the mine. Once the coal is delivered to the generating plant, its cost is added to plant inventory, dumped in a pile, and included within the company's rate base.[165]

2. This issue concerns whether the coal-in-transit, in other words, the coal that is sitting in a railcar, or barge, between the mine and the generating plant, should also be

[164] Transcript, Page 1057, Lines 9-13.

[165] Neff Rebuttal, Ex. 18, Page 5, Lines 8-9.

included in rate base. Ameren Missouri contends the coal-in-transit should be included in rate base. Staff and MIEC oppose the inclusion of that coal in rate base.

3. It is important to remember that this is a rate base issue. In other words, the question is whether the company should be able to earn a return on the value of the coal-in-transit. The cost of the coal is not charged to ratepayers until it is actually burned at the power plant.[166]

4. At any given moment, Ameren Missouri has large quantities of coal in transit, moving toward its generating plants.[167] The quantities and value of the coal-in-transit are highly confidential so an exact number will not be included in this report and order. However, inclusion of coal in-transit in rate base would increase Ameren Missouri's revenue requirement in this case by less than $1 million.[168]

5. Ameren Missouri takes title to the coal at the time it is put into its railcars at the mine. Thereafter, Ameren Missouri is the owner of the coal as it is being transported.[169] Generally, the coal is in transit for three or four days before it is added to inventory at the coal plant.[170]

6. The mine sends Ameren Missouri an invoice for the coal as it is delivered to the railcars. Ameren Missouri typically pays that invoice about two weeks later. As a result, the coal is usually not paid for until it is sitting in the coal pile at the generating

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[166] Transcript, Page 1411, Lines 5-13.
[167] Transcript, Page 1405, Lines 10-12.
[168] Transcript, Page 1419, Lines 2-6.
[169] Transcript, Page 1409, Lines 15-25.
[170] Transcript, Page 1408, Lines 20-24.

plant.[171] However, payment is simply a timing matter, unconnected to where the coal is located. Ameren Missouri would still have to pay for the coal when invoiced even if for some reason delivery was delayed and the coal was still sitting in a railcar.[172]

7. The amount of coal held in inventory in the coal piles at the generating plants was not at issue at the hearing in this case. However, MIEC argued that inclusion of coal in-transit as part of inventory would increase that inventory to a level higher than necessary.[173]

8. There was a good deal of testimony offered about what would be an optimum amount of coal to hold in inventory at the plant, most of it highly confidential, but all such testimony misses the point. The coal-in-transit is not part of inventory and allowing it in rate base would not make it a part of inventory. Rather, it is a separate rate base item. As Ameren Missouri's witness explained, coal inventory is coal that is on site that the company knows it can burn. Coal that is in transit may never arrive because of some disruption. Therefore, it is not counted as part of the coal inventory reserve for purposes of determining whether there is enough coal on hand to avoid running out of coal and having to shut the plant down.[174]

9. As previously indicated, Ameren Missouri actually pays for the coal approximately two weeks after it takes title to the coal at the mouth of the mine. Staff and MIEC contend that payment delay should preclude Ameren Missouri from including the coal-in-transit in rate base.

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[171] Transcript, Page 1400-1401, Lines 12-25, 1-17. This testimony was offered in camera, but the facts are not highly confidential.

[172] Transcript, Page 1410, Lines 15-20.

[173] Meyer Surrebuttal, Ex. 511, Page 28, Lines 3-15.

[174] Transcript, Page 1413, Lines 1-16.

10. In response to that argument, Ameren Missouri's witnesses pointed out that it has not yet paid for approximately one quarter of the coal sitting in the coal pile, but no one was arguing that coal in inventory should not be included in rate base.[175] Staff's witness at the hearing did not challenge that argument, but in its reply brief, Staff attempted to change its position impose a new adjustment to reduce "by 25 percent the value of the coal pile to reflect that Ameren Missouri has no investment in that coal."[176] However, such a position was not supported by any witness at the hearing.

11. The arguments about the two-week delay in paying for the coal are without merit. Ameren Missouri uses an accrual method of accounting. The coal goes on the company's books as an owned item when it takes ownership of the coal at the mine.[177] Using an accrual method of accounting, the timing of cash payments for inventory items is not a consideration in determining whether an inventory item should be included in rate base. Qualifying capital cost items are included in rate base whether they are paid for in advance, at the time of delivery, or after delivery. The test is whether those items are used and useful, not when payment is made.

12. Ameren Missouri's lead-lag study recognizes a 17.14-day lead for the time between when the coal is loaded into the railcars and the time Ameren Missouri pays for it. There is also a $53 million allowance for coal in the company's cash working capital allowance, which is also a rate base item. From this, Staff's witness argued for the first time at the hearing that allowing Ameren Missouri to include coal-in-transit in its rate base

[175] Transcript, Page 1421, Lines 2-12.

[176] Staff's Reply Brief, Page 34. Ameren Missouri filed a motion to strike that portion of Staff's brief on November 26, 2012. Staff responded on December 3 and agreed that its proposal to make a new adjustment in its reply brief was inappropriate and withdrew that portion of its brief. Ameren Missouri's motion to strike is now moot and on that basis is denied.

[177] Transcript, Page 1420, Lines 15-22.

would allow the company to double recover for that cost.[178]

13. The double recovery argument is not persuasive. The 17.14-day lead associated with the coal-in-transit measures the amount of time Ameren Missouri has use of the coal before paying for it. In other words, recognizing the 17.14-day lead in the cash working capital allowance means that allowance is lower than it would be if the lead were not taken into account. Since the cash working capital allowance is already in rate base, recognizing the lead tends to reduce rate base. Thus, recognizing coal-in-transit in rate base does not amount to double recovery, rather it simply offsets a reduction to rate base that has already been taken through the adjustment of the cash working capital allowance through the lead-lag study.

14. Staff also argues in its brief that coal-in transit should not be included in rate base "because coal in transit has never been included in rate base in the 100 years of utility regulation in Missouri, that's why." Interestingly, Staff's witness, Lisa Hanneken, indicated at the hearing that she could not make such a broad statement.[179] In any event, whether coal-in-transit has ever before been included in rate base is irrelevant. The Commission will make its decision on the evidence presented to it in this case, not on what may or may have not happened in the past hundred years.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall include the value of coal in transit in its rate base.

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[178] Transcript, Pages 1423-1424, Lines 3-25, 1-9.

[179] Transcript, Pages 1434-1435, Lines 20-25, 1-2.

10. Severance Costs and VS11: Should Ameren Missouri be authorized to amortize to rates over three years the approximately $25.8 million in costs incurred in its VS11 voluntary employee separation program?

Findings of Fact:

1. In 2011, Ameren Missouri reduced its workforce by offering a lump-sum severance package to some of its employees. Three hundred forty employees accepted the severance offer and left the employ of the company at the end of 2011.[180]

2. By reducing its workforce by 340 employees, Ameren Missouri has saved, and will continue to save, roughly $25 million per year. The severance package cost Ameren Missouri a one-time amount of approximately $25.8 million.[181] Ameren Missouri proposes to recover those one-time costs by amortizing the $25.8 million over three years.[182] That amounts to an increase of $8.6 million in annual revenue requirement.

3. Staff and MIEC oppose Ameren Missouri's proposed amortization of the cost of the severance package.

4. Ameren Missouri started to realize savings resulting from the reduction in its workforce as soon as it implemented the severance package. However, rates set in the last rate case assumed that the 340 employees would remain employed and the rates were set high enough to cover those costs. As a result, Ameren Missouri will be able to retain all those savings until new rates, using the new lower employment numbers, are set in this case. However, once the new rates go into effect, those savings will start flowing to ratepayers[183]

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[180] Baxter Direct, Ex. 1, Page 15, Lines 3-5.

[181] Carver Surrebuttal, Ex. 515, Page 3, Lines 7-9.

[182] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 101, Lines 12-13.

[183] Carver Direct, Ex. 514, Page 26, Lines 12-17.

5. Staff's witness, Lisa Ferguson, calculated the savings retained by Ameren Missouri up until new rates will go into effect on January 2, 2013 at roughly $26 million.[184] Ameren Missouri disagreed with some of the details of Ferguson's calculation, but conceded that the savings the company realized in 2012 roughly equal the severance costs.[185]

6. Despite having already recovered the costs of the severance package, Ameren Missouri asks the Commission to again recover those costs from ratepayers through a direct three-year amortization. Ameren Missouri contends such recovery is justified because ratepayers will ultimately benefit from the cost reductions resulting from the severance package in an amount much greater than the direct costs the company seeks to amortize.[186] Ameren Missouri also complains that from March 2009 through July 2012, the company actually under-recovered its payroll and benefit costs by $51 million.[187] Finally, Ameren Missouri argues that it should be allowed to recover the additional amortization so that it will have an incentive to pursue further cost-cutting measures.[188]

7. Ameren Missouri prudently took steps to reduce its payroll costs to improve the efficiency of its operations. Under the lag that results from the traditional regulatory model, the company is able to retain those cost savings until it chooses to come back for a rate adjustment and a new level of costs is used to reset rates. In this case, Ameren Missouri, for reasons unconnected to these particular costs, has asked the Commission to adjust its rates. The new rates will reflect the lower personnel costs and the company will

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[184] Ex. 242.

[185] Barnes Rebuttal, Ex. 12, Page 17, Lines 1-2.

[186] Barnes Rebuttal, Ex. 12, Page 16, Lines 14-17.

[187] Barnes Rebuttal, Ex. 12, Page 17, Lines 5-8, as corrected at Transcript, Page 1804.

[188] Barnes Rebuttal, Ex. 12, Page 17, Lines 12-14.

cease to benefit directly from the reduced payroll after having barely recovered its costs. If Ameren Missouri had not chosen to request a rate increase at this time, it would have continued to benefit from its reduced payroll costs. That is how the system works.

8. Ameren Missouri is essentially asking the Commission to require ratepayers to give the company a $25.8 million bonus to reward the company for being efficient in reducing its payroll and to give it an extra incentive to reduce costs in the future. The Commission finds that the company does not need and will not receive any extra incentive to operate efficiently.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri proposed amortization of the costs of its severance package are disallowed.

11. Return on Common Equity (ROE): In consideration of all relevant factors, what is the appropriate value for return on equity (ROE) that the Commission should use in setting Ameren Missouri's Rate of Return?

Findings of Fact:

1. This issue concerns the rate of return Ameren Missouri will be authorized to earn on its rate base. Rate base includes things like generating plants, electric meters, wires and poles, and the trucks driven by Ameren Missouri's repair crews. In order to determine a rate of return, the Commission must determine Ameren Missouri's cost of obtaining the capital it needs.

2. The relative mixture of sources Ameren Missouri uses to obtain the capital it needs is its capital structure. Ameren Missouri's actual capital structure as of the true-up

date, July 31, 2012 is:

Long-Term Debt	46.8%
Short-Term Debt	00.0%
Preferred Stock	01.1%
Common Equity	52.1%[189]

No party has raised an issue regarding capital structure so the Commission will not further address this matter.

3. Similarly, no party has raised an issue regarding Ameren Missouri's calculation of the cost of its long-term debt and preferred stock.

4. Determining an appropriate return on equity is the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, in determining a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Ameren Missouri rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market, without permitting an excessive rate of return on equity that would drive up rates for Ameren Missouri's ratepayers. In order to obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

[189] Martin Direct, Ex. 23, Page 7.

5. Three financial analysts offered recommendations regarding an appropriate return on equity in this case. Robert B. Hevert testified on behalf of Ameren Missouri. Hevert is Managing Partner of Sussex Economic Advisors, LLC, and Executive Advisor to Concentric Energy Advisors, Inc. of Marlborough, Massachusetts. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration degree from the University of Massachusetts.[190] He recommends the Commission allow Ameren Missouri a return on equity of 10.50 percent, within a range of 10.25 percent to 11.00 percent.[191]

6. Michael Gorman testified on behalf of MIEC. Gorman is a consultant in the field of public utility regulation and is a managing principal of Brubaker & Associates.[192] He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[193] Gorman recommends the Commission allow Ameren Missouri a return on equity of 9.30 percent, within a recommended range of 9.20 percent to 9.40 percent.[194]

7. Finally, David Murray testified on behalf of Staff. Murray is the Utility Regulatory Manager of the Financial Analysis Unit for the Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri – Columbia, and a Masters in Business Administration from Lincoln University. Murray has been employed by the Commission since 2000 and has offered testimony in many cases

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[190] Hevert Direct, Ex. 20, Page 1.

[191] Hevert Rebuttal, Ex. 21, Page 2, Lines 4-12.

[192] Gorman Direct, Ex. 507, Page 1, Lines 4-6.

[193] Gorman Direct, Ex. 507, Appendix A, Page 1, Lines 9-12.

[194] Gorman Direct, Ex. 507, Page 2, Lines 6-8.

before the Commission.[195] Murray recommends a return on equity of 9.0 percent, within a range of 8.00 percent to 9.00 percent.[196]

8. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and through stock price appreciation.[197] To comply with standards established by the United States Supreme Court, the Commission must authorize a return on equity sufficient to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[198]

9. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method assumes the current market price of a firm's stock is equal to the discounted value of all expected future cash flows.[199] The Risk Premium method assumes that the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium needed to compensate the investor for the additional risk of investing in equities compared to bonds.[200] The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.[201] No one method is any more "correct" than any other

[195] Staff Report Revenue Requirement Cost of Service, Ex. 202, Appendix 1, Page 49.
[196] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 13, Lines 17-22.
[197] Gorman Direct, Ex. 507, Page 11, Lines 2-6.
[198] Gorman Direct, Ex. 507, Page 11, Lines 7-17.
[199] Gorman Direct, Ex. 507, Page 13, Lines 7-10.
[200] Hevert Direct, Ex. 20, Page 36, Lines 9-15.
[201] Hevert Direct, Ex. 20, Page 31, Lines 8-18.

method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

10. Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at another number. For 2011, the average return on equity awarded to integrated electric utilities by state commissions in this country was 10.27 percent.[202] For the first six months of 2012, that average awarded return on equity dropped to 10.05 percent.[203] For just the second quarter of 2012, the average awarded return on equity was 9.92 percent.[204] For the third quarter of 2012, the average awarded return on equity dropped to 9.9 percent.[205]

11. The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on equity to Ameren Missouri. However, Ameren Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

12. Ameren Missouri's witness, Robert Hevert, recommended the Commission allow the company an ROE in a range from 10.25 to 11.00 percent, with a specific recommended ROE of 10.5 percent.[206] MIEC's witness, Michael Gorman, recommended an ROE in a range from 9.2 to 9.4 percent, with a specific recommended ROE of 9.3

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[202] Hevert Direct, Ex. 20, Page 39, Lines 9-14.

[203] Transcript, Page 1555, Lines 2-5. That figure excludes an unusually high incentive rate awarded to an electric utility in Virginia

[204] Transcript, Page 1555, Lines 15-16. *See also*, Ex. 530.

[205] Transcript, Pages 1558-1560. That number is calculated by averaging ROE awards to four vertically integrated electric utilities in the quarter.

[206] Hevert Rebuttal, Ex. 21, Page 2, Lines 6-9.

percent.[207] Staff's witness, David Murray, recommended an ROE in a range from 8.0 to 9.0 percent, with a specific recommended ROE of 9.0 percent.[208] However, in its initial brief, Staff suggested that an ROE of 9.45 percent might be more appropriate.[209] AARP and Consumer's Council did not offer an ROE expert witness, but they recommend the Commission adopt an ROE of 8.0 percent, which is the low end of David Murray's range. Public Counsel also did not offer an ROE expert witness, but advises the Commission to adopt an ROE at the low end of a reasonable range to best protect the interests of ratepayers.

13. The Commission will examine the analysis presented by each of the experts in more detail later in this order. But before doing so, the Commission notes that the cost of equity has trended downward since Ameren Missouri's ROE was established in its last rate case. Utility bond yields have declined by approximately 70 to 110 basis points since that last rate case. That decline in utility bond yields suggest that Ameren Missouri's cost of capital is lower now than it was then.[210] That decline is reflected in the trend noted above in declining allowed ROE in the last year. Even Ameren Missouri's expert, Mr. Hevert agrees that the cost of equity has gone down since the last case. As he puts it, "the question is by how much.[211]

14. Looking at the recommendation of Staff's expert first, the Commission finds that David Murray's recommendation is unreasonably low. If the Commission were to award Ameren Missouri an ROE of 9.0 percent as Murray recommends, it would be the

[207] Gorman Direct, Ex. 507, Page 2, Lines 6-9.

[208] Staff Report, Revenue Requirement Cost of Service, Ex. 202, Page 13, Lines 17-21.

[209] Staff's Initial Brief, Page 89.

[210] Gorman Direct, Ex. 507, Page 5, Lines 7-9.

[211] Transcript, Page 1548, Lines 3-4.

second lowest non-penalty ROE awarded to an energy utility in the United States in the last thirty years.[212] Furthermore, Murray testified at the hearing that he actually believes Ameren Missouri's cost of equity may be below 8.0 percent and he only raised his recommendation to 9.0 percent in recognition that the Commission would not award an ROE below 8.0 percent.[213]

15. Even Murray does not believe the Commission will actually award Ameren Missouri an ROE of 9.0 percent based on his recommendation. Instead, he is trying to convince the Commission to award an ROE below 10.0 percent.[214] That is probably why Staff essentially abandoned Murray's recommendation after the hearing. In its Initial Brief, Staff recommended that the Commission award Ameren Missouri an ROE of 9.45 percent, using Murray's 9.0 percent ROE recommendation as the low end of a possible range, bounded at the top by the national average ROE of 9.9 percent.[215]

16. Ameren Missouri's witness, Robert Hevert, primarily relied on two forms of the DCF model to make his recommendation that the Commission award the company an ROE of 10.5 percent.[216]

17. However, Hevert's estimation of an appropriate ROE is too high. MIEC's witness, Michael Gorman explains that Mr. Hevert relied on long-term sustainable growth rate estimates in his DCF models that are higher than the growth outlook of the economy as a whole. As he explained, it is not rational to expect that utilities can grow faster than the economies in which they provide service because utilities provide service to meet the

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[212] Hevert Rebuttal, Ex. 21, Page 28, Footnote 57.

[213] Transcript, Page 1979-1980, Lines 23-25, 1-20.

[214] Transcript, Page 1980, Lines 17-24.

[215] Staff's Initial Brief, Page 89.

[216] Hevert Direct, Ex. 20, Page 18, Lines 15-16.

demand of the economies they serve.[217] After correcting this, and other flaws in Hevert's multi-stage DCF model, Gorman showed that model as yielding a ROE of 9.46 percent instead of the 10.74 percent derived by Hevert.[218]

18. Although the Commission finds Michael Gorman to be the most credible and most understandable of the three ROE experts who testified in this case, his recommendation that the Commission award Ameren Missouri an ROE in a range from 9.2 to 9.4 percent also has weaknesses.

19. Ameren Missouri's extensive cross-examination of Gorman revealed that Gorman's evaluation is dependent on many assumptions. The same is true of any other expert and illustrates why ROE analysis is as much an art as a science. Specifically, that cross-examination showed that Gorman performed a risk premium analysis that relied on indicated risk premium data from 1986 through 2012. He then excluded the three highest and three lowest years from his analysis and arrived at an indicated ROE of 9.26 percent.[219] However, the three years that Gorman excluded from his analysis as too high were from three of the four most recent years, 2008, 2009, and 2011. The three years he excluded from his analysis as too low were from the early period of the study. As a result, the study wound up relying on risk premium data from 1986 and 1987 to calculate an ROE for today.[220]

20. Manipulating the data in a slightly different manner, using just a simple average of the last ten years of data, would result in an indicated ROE of 9.6 percent

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[217] Gorman Direct, Ex. 507, Page 44, Lines 10-12.

[218] Gorman Rebuttal, Ex. 507, Page 50, Table 8.

[219] Transcript, Pages 1728-1732.

[220] Transcript, Page 1732, Lines 14-25.

instead of 9.26 percent. Weighting that ten-year average would indicate an ROE of 9.76 percent.[221]

21. Similarly, the cross-examination revealed that if Gorman relied on the mean rather than the median for his proxy groups within his DCF analysis, his indicated ROE would have been 9.7 percent rather than 9.4 percent.[222]

22. That testimony does not show that Gorman was dishonest or unreliable. On the contrary, the Commission found his testimony to be reliable and persuasive. However, the cross-examination clearly revealed that any expert analysis is subject to the many decisions that go into choosing among the data to be included in the various formulas. As a result, the opinions offered by the ROE experts cannot be blindly accepted as scientifically or legally binding on the Commission.

23. After considering and balancing all the information before it, the Commission is concerned that Gorman's recommended ROE is too low. The national average awarded ROE in recent months is around 10.0 percent. Gorman's analysis indicates a return somewhere below 10.0 percent is appropriate. However, Gorman also testified that dropping a utility's allowed ROE too precipitously could be harmful to the company. He explained:

> caution is necessary in awarding a return on equity for an electric utility company because dropping that authorized return on equity too fast can create financial trouble, even if the return on equity reflects fair compensation in the marketplace.[223]

He then went on to say:

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[221] Transcript, Page 1737, Lines 12-24.

[222] Transcript, Pages 1745-1756.

[223] Transcript, Page 1774, Lines 18-22.

> my concern is that if the cost of capital drops and stays low, the utility needs time to modify its financial housekeeping in order to maintain its financial integrity while receiving a very low authorized return on equity, even if it is consistent with current market costs.[224]

24. In addition, Ameren Missouri must compete for capital with other utilities. Awarding Ameren Missouri an ROE that is 60 or 70 basis points below the national average could cause that available capital to flow away from Ameren Missouri to the detriment of both shareholders and ratepayers.

25. After considering all the competent and substantial evidence presented on this issue, the Commission finds that an ROE of 9.8 percent is appropriate.

Conclusions of Law:

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate to the particular application' (quoting *Southwestern Bell Telephone Company v. Arkansas Public Service Commission,* 593 S.W. 2d 434 (Ark 1980).[225]

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[226]

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[224] Transcript, Page 1775, Lines 8-13.

[225] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[226] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

B. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a “precise science”:

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of ‘precise science,’ because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[227]

Decision:

Based on the evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company’s ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.8 percent is a fair and reasonable return on equity for Ameren Missouri. The Commission finds that this rate of return will allow Ameren Missouri to compete in the capital market for the funds needed to maintain its financial health. Furthermore, this allowed return on equity is well within the zone of reasonableness that Missouri’s courts have applied when reviewing Commission decisions regarding return on equity.

12. Fuel Adjustment Clause (FAC):

Should Ameren Missouri’s fuel adjustment clause be continued?

Findings of Fact:

1. Before addressing other issues regarding the implementation of Ameren Missouri’s fuel adjustment clause, the Commission must address the more fundamental

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[227] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

issue of whether Ameren Missouri should be allowed to continue to use a fuel adjustment clause.

2. In a previous Ameren Missouri rate case, ER-2008-0318, the Commission allowed Ameren Missouri to implement a fuel adjustment clause.[228] The approved fuel adjustment clause includes an incentive mechanism that requires Ameren Missouri to pass through to its customers 95 percent of any deviation in fuel and purchased power costs from the base level. The other 5 percent of any deviation is retained or absorbed by Ameren Missouri.[229] The Commission has approved the continuation of that fuel adjustment clause in each subsequent Ameren Missouri rate case.

3. In this case, Ameren Missouri proposed that the Commission allow it to continue to use its existing fuel adjustment clause.[230] AARP and Consumers Council did not present any testimony on this issue, but they did cross examine witnesses presented by other parties and urge the Commission to discontinue Ameren Missouri's fuel adjustment clause. Staff did not oppose the continuation of the fuel adjustment clause, but advises the Commission to change the sharing mechanism to create an 85/15 split, with Ameren Missouri retaining or absorbing 15 percent of any deviation from the base level of fuel and purchased power costs. MIEC supports Staff's position. The Commission will address the proposed modification of the sharing mechanism in the next section of this report and order.

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[228] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

[229] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 76.

[230] Barnes Direct, Ex. 11, Page 6, Lines 2-4.

4. When it first allowed Ameren Missouri to implement a fuel adjustment clause in a previous rate case, ER-2008-0318, the Commission found that Ameren Missouri should be allowed to establish a fuel adjustment clause because its fuels costs were substantial, beyond the control of the company's management, and volatile in amount. The Commission also found that Ameren Missouri needed a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity and to be able to compete for capital with other utilities that have a fuel adjustment clause.[231] In the same rate case, the Commission found that a 95/5 sharing mechanism would give Ameren Missouri a sufficient opportunity to earn a fair return on equity, while protecting customers by preserving the company's incentive to be prudent.[232]

5. Nothing has changed in the years since the Commission established Ameren Missouri's fuel adjustment clause to cause the Commission to change that decision. The Commission again finds that Ameren Missouri's fuel and purchased power costs are substantial, $941 million in the test year, comprising 47 percent of the company's total operations and maintenance expense.[233] Furthermore, the revenue the company receives from off-system sales, which is also tracked through the fuel adjustment clause, is also substantial, estimated to total approximately $360 million per year.[234] Those fuel and purchased power costs continue to be dictated by national and international markets, and

[231] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

[232] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 76.

[233] Barnes Direct, Ex. 11, Page 8, Lines 14-17.

[234] Barnes Direct, Ex. 11, Page 8, Lines 17-20.

thus are outside the control of Ameren Missouri's management.[235] Finally, these costs and revenues continue to be volatile, particularly off-system sales. For example, annual average wholesale prices decreased approximately $3 per megawatt-hour (MWh), or approximately 10 percent since February 2011, when Ameren Missouri rebased fuel costs in the last rate case. That reduction in wholesale electricity prices caused a $30 million decrease in annual off-system sales revenues despite comparable sales volumes.[236] That volatility also means the fuel adjustment clause has benefited ratepayers in those periods when the company's net fuel costs have decreased.

6. Furthermore, the Commission finds that Ameren Missouri still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. In addition, Ameren Missouri still must compete in the capital markets with other utilities and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.[237]

Conclusions of Law:

A. Section 386.266.1, RSMo (Supp. 2011), allows the Commission to establish and continue a fuel adjustment clause for Ameren Missouri.

Decision:

Ameren Missouri still needs to have a fuel adjustment clause in place if it is to have a reasonable opportunity to earn a fair return on its investments. The Commission concludes

[235] Barnes Direct, Ex. 11, Page 8, Lines 20-23.

[236] Barnes Direct, Ex. 11, Pages 8-9, Lines 23-26, 1-3.

[237] Barnes Direct, Ex. 11, Page 10, Lines 3-16.

that Ameren Missouri should be allowed to continue to implement the previously approved fuel adjustment clause.

A. Should the sharing percentage in Ameren Missouri's fuel adjustment clause be changed to 85%-15%?

Findings of Fact:

1. While Staff did not oppose the continuation of Ameren Missouri's fuel adjustment clause, it advised the Commission to modify the sharing mechanism within the fuel adjustment clause to increase the percentage of costs and income absorbed or retained by Ameren Missouri from 5 percent to 15 percent. MIEC did not present any additional testimony on this question, but supports the modification proposed by Staff. AARP and Consumers Council also did not present any additional testimony on this question, but if the Commission does not totally eliminate the FAC, they advocate for a 50-50 split between rate payers and shareholders.

2. Staff offered five reasons why the sharing percentage should be changed. First, Staff points out that under the current 95%-5% sharing percentage, Ameren Missouri had to absorb only $15.3 million out of its net total fuel and purchased power cost of $1.4 billion, or about 1.1 percent of its net energy costs. If that sharing percentage had been changed to 85%-15%, as Staff advocates, Ameren Missouri would have had to absorb $45.9 million, or 3.3 percent of its net energy costs. If it did not have an FAC at all, Ameren Missouri would have had to absorb $306 million, or 21.8 percent of its net energy costs.[238] In essence, Staff suggests Ameren Missouri should be thankful it has an FAC and not quibble about the sharing percentage.

3. Second, Staff points out that Ameren Missouri's off-system sales margins are

[238] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 164, Lines 5-15.

more volatile than its fuel costs. If the sharing percentage were changed to 85%-15% as Staff proposes, Ameren Missouri would be able to keep a greater percentage of the off-system sales margins.[239]

4. Third, Staff claims that increasing the sharing percentage to 85%-15% would give Ameren Missouri a greater incentive to increase its fuel cost savings or to make more off-system sales.[240]

5. Fourth, Staff claims that increasing the sharing percentage to 85%-15% would increase Ameren Missouri's incentive to accurately estimate the net base energy cost factors in its general rate cases.[241]

6. Fifth, Staff complains that Ameren Missouri used the FAC process to delay payment to ratepayers under the company's second prudence review case, EO-2012-0074.[242] The Commission will address each of Staff's concerns in turn.

7. It is easy for Staff to say that Ameren Missouri should not complain about a proposal to triple the amount of net energy costs it must absorb under the fuel adjustment clause from $15 million to $45 million. But that extra $30 million represents prudently incurred net fuel costs that the company would never be able to recover. Even to a company as large as Ameren Missouri, $30 million is not *de minimis*. Certainly, much time and energy has been expended in this case on issues that are worth substantially less than $30 million.

8. Ameren Missouri's off-system sales margins are volatile because power

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[239] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 165, Lines 7-11.
[240] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 165, Lines 12-17.
[241] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 166, Lines 1-7.
[242] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 166, Lines 8-16.

prices are volatile[243] and Staff's proposal would allow the company to keep a greater percentage of off-system sales. However, that fact would not necessarily benefit the company. The company could just as easily be harmed if off-system sales decreased to below the level included in rates. The volatility of off-system sales is an argument for keeping the sharing mechanism at 95%-5%, not for changing it.

9. Staff contends that increasing the sharing percentage to 85%-15% would give Ameren Missouri a greater incentive to minimize its costs and maximize its off-system sales. However, a greater incentive would be meaningless if there is little the company can actually do to minimize costs or maximize off-system sales. In general, Ameren Missouri's fuel costs are dictated by national and international markets that are largely beyond the company's control.[244] Ameren Missouri already sells all of its available, in-the-money generation into the MISO market so there is little, if any, opportunity for Ameren Missouri to increase its off-system sales no matter how much incentive it is given.[245] Furthermore, Staff has not alleged that Ameren Missouri has acted imprudently in minimizing its fuel costs or maximizing its off-system sales.[246]

10. Staff claims that increasing the sharing percentage to 85%-15% would increase Ameren Missouri's incentive to accurately estimate the net base energy cost factors in its general rate cases. Specifically, Staff's witness suggested that the increase would provide the company with a greater incentive to look for better predictors of future

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[243] Haro Rebuttal, Ex. 25, Pages 2-3, Lines 22,1.

[244] Barnes Direct, Ex. 11, Page 8, Lines 21-23.

[245] Haro Rebuttal, Pages 15-16, Lines 15-21, 1-4.

[246] Transcript, Page 1221, Lines 1-17.

power costs.[247] However, Staff's witness did not know of any better predictors of future power costs,[248] and she was unwilling to utilize forward price projections even if they might be a better predictor.[249]

11. Finally, Staff complains about Ameren Missouri's decision to include AEP and Wabash revenues in the FAC and argues the company misused the FAC to delay repaying that revenue to ratepayers. The Commission directed Ameren Missouri to remove the AEP and Wabash revenues from its FAC in a report and order issued in 2011 in File Number EO-2010-0255. That decision has since been appealed to the Missouri Court of Appeals. The case Staff specifically references, EO-2012-0074, shares the same issues and is currently pending before the Commission. In the last rate case, the Commission rejected Staff's argument that Ameren Missouri's alleged imprudence regarding the AEP and Wabash revenues demonstrated a need for the company to have a greater incentive under the FAC.[250] Surely the Commission has no desire to try to punish Ameren Missouri for exercising its legal right to appeal the Commission's decision in EO-2010-0255. In short, Ameren Missouri has not misused the FAC process and Staff's argument is without merit.

12. Furthermore, changing the sharing percentage without a good reason to do so could erode investor confidence in the utility and cast a shadow on the state regulatory process.[251]

13. Most significantly, a change in the sharing mechanism to require Ameren

[247] Mantle Surrebuttal, Ex. 224, Page 8,Lines 8-12.

[248] Transcript, Page 1236, Lines 17-19.

[249] Transcript, Page 1237, Lines 6-12.

[250] In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service, File Number ER-2011-0028, Report and Order, Issued July 13, 2011, Pages 82-83.

[251] Barnes Direct, Ex. 11, Page 10, Lines 14.16.

Missouri to absorb 15 percent of net fuel cost changes instead of the current 5 percent would impose a significant financial burden on the company. If the proposed 85%-15% sharing mechanism had been in place since the fuel adjustment clause was put into effect instead of the actual 95%-5% sharing mechanism, Ameren Missouri would have been required to absorb an additional $30 million in net fuel costs.[252] That would be a heavy burden on a company that is already having difficulty earning its allowed rate of return.

Conclusions of Law:

A. Section 386.266.1, RSMo (Supp. 2011), the statute that allows the Commission to establish a fuel adjustment clause provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation. The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:
>
> *(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;*
>
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the

[252] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 164, Lines 5-15.

> utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
>
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …
>
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows Ameren Missouri to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

B. Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

C. Specifically, Commission Rule 4 CSR 240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. Ameren Missouri has met those filing requirements.

Decision:

Staff's stated reasons for experimenting with adjusting the sharing mechanism of Ameren Missouri's fuel adjustment clause to implement an 85%-15% split do not withstand scrutiny. Imposing a significant financial burden on the company simply to experiment with an alternative sharing percentage would be unfair to the company. The Commission finds that there is no reason to change the sharing percentages in the fuel adjustment clause under which Ameren Missouri has operated for the past several years. The Commission will retain the current 95%-5% sharing mechanism included in Ameren Missouri's fuel adjustment clause.

B. MISO Costs in the FAC:

Findings of Fact:

1. Through its membership in the Midwest Independent Transmission System Operator, Inc. (MISO), Ameren Missouri has access to a transparent energy market where it can acquire power to serve its load and sell power off-system. As part of its membership in MISO, Ameren Missouri incurs certain transmission charges for the load it serves through the MISO market.[253] Ameren Missouri incurs a variety of charges from MISO for the use of its service. Ameren Missouri cannot pick and choose which of these charges it will pay, all are required charges.[254] Furthermore, no party is disputing the amount of the MISO charges or the fact that Ameren Missouri must pay them. Ameren Missouri is currently flowing MISO transmission charges through the fuel adjustment clause.

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[253] Haro Sur-Surrebuttal, Ex. 26, Page 6, Lines 6-9.

[254] Haro Rebuttal, Ex. 25, Page 22, Lines 12-16.

2. Since January 2012, Ameren Missouri has begun to incur charges under MISO tariff schedule 26A. As with the other MISO transmission charges, including charges incurred under schedule 26,[255] Ameren Missouri has flowed those charges through the fuel adjustment clause.[256]

3. When Staff realized that what it terms the cost of building transmission lines would be included under MISO tariff schedules 26 and 26A, it proposed that those charges be excluded from recovery under the fuel adjustment clause.[257] MIEC arrived at essentially the same position and would exclude all charges for long-term transmission service from the fuel adjustment clause.[258]

4. The Ameren Missouri tariff provision in question concerns Factor CPP, which determines what costs may be flowed through the FAC. That tariff provision states as follows:

> Costs of purchased power reflected in FERC Account Numbers 555, **565**, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, **and excluding capacity charges for contracts with terms in excess of one (1) year,** incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations. … [259] (emphasis added).

5. Under the Federal Energy Regulatory Commission's Uniform System of Accounts, transmission charges for the transmission of the utility's electricity over transmission facilities owned by others are to be recorded in account 565.[260] Since the

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[255] Transcript, Page 1195, Lines 14-17.

[256] Transcript, Page 1173, Lines 19-23.

[257] Mantle Surrebuttal, Ex. 224, Page 3, Lines 24-28.

[258] Dauphinais Surrebuttal, Ex. 518, Pages 9-16.

[259] Mantle Surrebuttal, Ex. 224, Page 3, Lines 10-17.

[260] Exhibit 80.

tariff specifically provides that costs of purchased power reflected in account 565 are to be flowed through the fuel adjustment clause, Ameren Missouri acted appropriately in doing so. Indeed, Staff agreed that account 565 costs were to be passed through the fuel adjustment clause within the current language of the tariff[261] and no party has alleged that Ameren Missouri should be required to make any adjustment for transmission charges that have already been passed through the fuel adjustment clause.

6. However, MIEC argues that the highlighted exclusion in the tariff provision of "capacity charges for contract with terms in excess of one (1) year" would exclude most schedule 26 and 26A charges from the fuel adjustment clause because those charges are for contracts with terms in excess of one year.[262] However, the tariff's exclusion of capacity charges for contract with terms in excess of one year refers to generation capacity, not transmission capacity. That interpretation of the tariff is supported by Ameren Missouri's witness, Jaime Haro, when he testifies "[c]apacity is commonly understood – in the markets and in Missouri regulation – as generation capacity."[263] Staff's witness, Lena Mantle, confirms that the intent of the tariff's exclusion was to apply to generation capacity.[264] The Commission finds that the tariff's exclusion applies only to generation capacity and not transmission capacity.

7. Actually, whether the tariff's current exclusion applies to generation capacity or transmission capacity is not the important question before the Commission. Even if the current tariff were interpreted to exclude transmission capacity, the Commission could, in

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[261] Transcript, Page 1243, Lines 10-13.

[262] Dauphinais Surrebuttal, Ex. 518, Pages 13-14, Lines 8-24, 1-8.

[263] Haro Sur-Surrebuttal, Ex. 26, Page 11, Lines 6-7.

[264] Transcript, Page 1244, Lines 5-16.

this case, direct Ameren Missouri to modify its tariff to explicitly include transmission capacity. The more important question before the Commission is whether that tariff should exclude the capacity charges challenged by Staff and MIEC.

8. MIEC's witness, James Dauphinais, explains that MISO schedule 26 charges are for long-term transmission service the utility takes under MISO tariff schedule 9 to serve its network load and short-term transmission services it takes under MISO tariff schedule 7 and MISO tariff schedule 8 to make off system sales on behalf of its retail customer to entities not located within MISO or PJM. Currently, schedule 26 is used by MISO to recover the cost of Baseline Reliability Projects of 345 kV or higher voltage that are included in the MISO Transmission Expansion Plan.[265]

9. Dauphinais also explains that MISO schedule 26A charges are incurred by Ameren Missouri for long-term transmission service it takes under MISO tariff schedule 9 to serve its network load and short-term transmission services it takes under MISO tariff schedule 7 and MISO tariff schedule 8 to make off-system sales, on behalf of its retail customers, to entities not located within MISO or PJM. MISO schedule 26A is used to recover the cost of Multi-Value Transmission Projects (MVPs).[266]

10. The MVPs are of particular concern because the MISO Board of Directors has approved $5.6 billion of new MVP construction through 2021. MISO will collect the cost of these MVPs from all MISO transmission customers for the benefit of the transmission owners who are, or who will, construct the MVPs.[267]

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[265] Dauphinais Surrebuttal, Ex. 518, Page 11, Lines 3-15.

[266] Dauphinais Surrebuttal, Ex. 518, Page 12, Lines 6-16.

[267] Dauphinais Surrebuttal, Ex. 518, Page 12, Lines 16-20.

11. About eight percent of the MVP's will be built within Missouri.[268] Furthermore, only about $250 million of the $5.6 billion approved by MISO for MVPs will be used for construction in Missouri.[269] Ameren Missouri does not plan to build any MVPs within its service territory,[270] but Ameren Transmission Company (ATX), an affiliate of Ameren Corporation may build one or more MVPs in Ameren Missouri's service territory.[271]

12. The MISO transmission revenues associated with MVPs will ultimately flow to the owners of that transmission. That means that if ATX or another Ameren Corporation affiliate builds the MVP, those revenues, which are paid by Ameren Missouri's ratepayers, will go to the Ameren Corporation affiliate instead of being used to offset the charges paid by Ameren Missouri's ratepayers.[272]

13. Staff is concerned that ATX or another affiliate will build the MVP's instead of Ameren Missouri and thereby siphon off the transmission revenue that would otherwise go back to Ameren Missouri. However, Ameren Missouri has no particular right of first refusal to build such projects, cannot dictate to Ameren Corporation how other affiliated companies invest money, and may not have sufficient capital to build such projects while also maintaining reliable service within its own service territory.[273]

14. Since the construction of MVPs is just getting underway, associated transmission charges are expected to rise in the future. Right now, through the true-up period for this case, the twelve months ending July 31, 2012, those transmission costs are

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[268] Transcript, Page 1200, Lines 1-5.

[269] Transcript, Pages 1361-1362, Lines 18-25, 1-4.

[270] Transcript, Page 1175, Lines 20-25.

[271] Oligschlaeger Responsive Testimony, Ex. 240, Page 8, Lines 7-17.

[272] Oligschlaeger Responsive Testimony, Ex. 240, Page 8, Lines 17-19.

[273] Transcript, Pages 1308-1309.

$25.8 million. By 2016, they are projected to rise to nearly $53 million.[274] Ameren Missouri anticipates those costs will rise by 24 percent per year.[275]

15. Right now, MISO transmission costs paid by Ameren Missouri are nearly offset by MISO revenues received by Ameren Missouri as a transmission owner.[276] But as MVPs are built, transmission costs will rise faster than revenues simply because most of the MVPs are being built outside Missouri.[277]

16. Ameren Corporation is a member of MISO, but it has little control over MISO transmission charges.[278]

17. MISO transmission charges are volatile because no one knows for sure how much those MVP projects will costs once construction is complete.[279]

18. All parties agree that Ameren Missouri must be able to recover the MISO transmission charges in some manner. If the charges are not flowed through the FAC, the Commission will need to allow the company to recover those charges in base rates. The only issue is whether Ameren Missouri should be allowed to flow those charges through the fuel adjustment clause.

19. Since Ameren Missouri must be allowed to recover the MISO transmission charges in some manner, the continuation of the current practice of passing those costs through the fuel adjustment clause is the most logical manner of doing so. Those costs meet the Commission's past standards for inclusion in the fuel adjustment clause in that

[274] Haro Surrebuttal, Ex. 26, Page 8, Line 2.

[275] Transcript, Page 1362, Lines 18-24.

[276] Oligschlaeger, Responsive Testimony, Page 7, Lines 11-15. The exact numbers are highly confidential.

[277] Transcript, Page 1296, Lines 12-23.

[278] Transcript, Page 1290, Lines 13-19. Also Page 1246, Lines 6-14.

[279] Transcript, Page 1290, Lines 1-19.

they are significant in amount, volatile in that they are not only rapidly rising, but are also uncertain in amount, and they are largely beyond the control of Ameren Missouri. The Commission finds that MISO transmission costs should continue to be flowed through Ameren Missouri's fuel adjustment clause.

Conclusions of Law:

A. Commission Rule 4 CSR 240-20.030 requires electric utilities to keep all accounts in accordance with the Uniform System of Accounts.

B. Under the Filed Rate doctrine, the Commission must allow Ameren Missouri to recover in some manner the transmission charges imposed under the FERC approved MISO tariff.[280]

C. Staff presents a legal argument against inclusion of the MISO transmission charges in the fuel adjustment charge based on two Missouri statutes. The first statute Staff references is the statute that authorizes the establishment of a fuel adjustment clause. Section 386.266.1, RSMo (Supp. 2011) allows an electric utility to apply to the Commission for a mechanism to permit the utility to make periodic rate adjustments to "reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation."

D. Staff argues that transmission of electricity over electric lines is not the transportation of electricity within the meaning of the statute and therefore, transmission costs cannot properly be flowed through the fuel adjustment clause. Staff would limit the meaning of "transportation" within the statute to the transportation of fuel, such as coal. However, the phrase "including transportation" within the statute modifies both "fuel" and

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[280] *Nantahala Power and Light Co. v. Thornburg,* 476 U.S. 953, 106 S.Ct. 2349 (1986).

"purchased-power" costs. Since there is no way to transport electricity, in the form of purchased-power, except by transmission over electric lines, the statute that allows electric utilities to include transportation costs as part of purchased power costs must have been intended to allow transmission costs to be included within a fuel adjustment clause.

E. The second statute cited by Staff is Missouri's anti-CWIP statute, Section 393.135, RSMo 2000. That statute states:

> Any charge made or demanded by an electrical corporation for service, or in connection therewith, which is based on the costs of construction in progress upon any existing or new facility of the electrical corporation, or any other cost associated with owning, operating, maintaining, or financing any property before it is fully operational and used for service, is unjust and unreasonable, and is prohibited.

Staff contends that statutory provision would prohibit the inclusion of the Article 26 and 26A MISO charges within the fuel adjustment charge because MISO is using those charges to allow transmission owners to recover the costs of building new transmission projects.

F. Of course, if the anti-CWIP statute really applied to prohibit recovery of these transmission charges through the fuel adjustment charges, it would also prohibit their recovery by any method until the new transmission facilities were put in service. Any attempt by the Commission to deny Ameren Missouri the ability to recover duly imposed, FERC-approved charges would violate the filed-rate doctrine.

G. Even if the inclusion of the capital construction costs associated with the construction of MVP and other transmission projects in the fuel adjustment clause does not violate the anti-CWIP statute, Staff contends the recovery of such construction costs through the fuel adjustment clause would be bad public policy because the fuel adjustment clause should not be used to recover construction costs.[281]

H. However, both Staff's reliance on the anti-CWIP statute and its public policy argument rely on a mischaracterization of the nature of the transmission charges that Ameren Missouri seeks to flow through the fuel adjustment clause. MISO may use those charges to allow the transmission owner to recover the cost of constructing the transmission. But from Ameren Missouri's perspective, it is paying a FERC approved transmission charge, nothing more and nothing less. To Ameren Missouri it makes no difference how the transmission owner uses the revenue it receives through FERC.

I. When Ameren Missouri pays the transmission charges it is in the same position as an Ameren Missouri customer who pays their electric bill. The customer pays an established rate for the amount of electricity used. It is meaningless to try to parse out how much of that payment is for the cost of a new transformer in the neighborhood, or how much is paid toward the CEO's salary. The customer is paying a legally established charge that covers all the costs associated with the electricity used and Ameren Missouri is paying a legally established charge that covers all the costs associated with the transmission services it is using.

J. The Commission concludes there is no legal or public policy impediment to allowing Ameren Missouri to recover MISO transmission charges through the fuel adjustment clause.

Decision:

The Commission finds that Ameren Missouri may pass MISO transmission charges through its fuel adjustment clause.

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[281] Mantle Surrebuttal, Ex. 224, Page 4, Lines 14-22.

The Sixth Non-Unanimous Stipulation and Agreement:

Having decided that Ameren Missouri's fuel adjustment clause will be continued, the Commission must now take up the sixth nonunanimous stipulation and agreement that was signed by Ameren Missouri, Staff, and MIEC and filed on November 2. As explained earlier in this report and order, AARP and Consumers Council objected to that stipulation and agreement because it assumed the Commission would renew Ameren Missouri's fuel adjustment clause in some form, a result that was contrary to AARP and Consumers Council's position.

That stipulation and agreement dealt with technical details regarding 1) class kilowatt-hours, revenues and billing determinants; 2) fuel costs, purchased power costs, off-system sales revenues and base factors; and 3) fuel adjustment clause tariff sheets. In particular, the stipulation and agreement set out alternative model tariff sheets that would be used depending upon how the Commission decided the sharing percentage and MISO transmission cost issues. Those technical details were not the subject of testimony or other evidence at the hearing.

Because of the objection, the Commission cannot approve the stipulation and agreement. However, that stipulation and agreement is now the joint position statement of the signatory parties and no party has presented any evidence to counter that joint position. Therefore, the Commission finds that the joint position of the parties described in the sixth nonunanimous stipulation and agreement is appropriate and shall be incorporated in the compliance tariffs that Ameren Missouri will be directed to file as a result of this report and order.

B. Should Ameren Missouri be allowed to track transmission charges for recovery in a future rate case?

C. If a tracker is allowed, should it be subject to the conditions proposed by Staff?

Decision:

If the Commission had refused to allow Ameren Missouri to continue to recover MISO transmission charges through the fuel adjustment charge, Ameren Missouri proposed that it be allowed to track and defer those costs for possible recovery in a future rate case. Since the Commission has allowed those charges to be recovered through the fuel adjustment clause, these issues are now moot.

13. Storm Costs Tracker: Should the Commission establish a two-way storm restoration cost tracker whereby storm-related non-labor operations and maintenance (O&M) expenses for major storms would be tracked against the base amount with expenditures below the base creating a regulatory liability and expenditures above the base creating a regulatory asset, in each case along with interest at the Company's AFUDC rate?

Findings of Fact:

1. Ameren Missouri has proposed to implement a two-way storm restoration tracker to deal with storm-related non-labor operations and maintenance (O&M) expenditure for major storms.[282] Under that proposal, the Commission would establish a base level of expected major storm restoration O&M costs in the company's revenue requirement. Actual expenditures would then be tracked above or below that base level to create a regulatory asset or liability that the Commission would consider for amortization and recovery in the company's next rate case.[283]

2. Staff, MIEC, and Public Counsel oppose the creation of a storm restoration tracker.

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[282] The capital costs incurred for storm restoration are included in rate base and recovered in that manner.

[283] Barnes Direct, Ex. 11, Page 14, Lines 1-14.

3. Under regulation as it is currently practiced, major storm costs are recovered through base rates by inclusion of an expected level of costs determined by averaging historical storm related costs over several years. Occasionally, however, the utility's service territory will be hit by an extraordinary storm with many customers out of service, requiring massive repair and restoration efforts. For most extraordinary storm events that occur outside a rate case test year, the Commission has allowed the affected utility to defer those costs through an accounting authority order (AAO) for possible recovery in a future rate case.[284]

4. The Commission has frequently approved such AAOs and has allowed Ameren Missouri to recover its extraordinary storm recovery costs through an AAO and subsequent five-year amortizations. In fact, the company's current revenue requirement contains four separate amortizations related to extraordinary storm restoration costs.[285]

5. The current system has allowed Ameren Missouri to recover all of its major storm recovery costs in recent years. For the period from March 1, 2009, when rates from Case No. ER-2008-0318 went into effect, until the July 31, 2012 true-up cut-off date for this case, Ameren Missouri has, or will, collect in rates approximately $8.2 million more than the actual costs it incurred to restore service.[286]

6. If major storm restoration costs do not rise to the level included in base rates, Ameren Missouri gets to keep the extra earnings. That has also happened in recent years, as in 2010, when $6,400,000 was allowed for such expenses in base rates and the

[284] Boateng Rebuttal, Ex. 207, Page 4, Lines 1-14.

[285] Wakeman Surrebuttal, Ex. 32, Page 3, Lines 1-3.

[286] Meyer Surrebuttal, Ex. 511, Page 12, Lines 8-21 and Schedule GRM-SUR-1.

company had actual expenses of only $38.[287]

7. The two-way storm restoration costs tracker would not allow Ameren Missouri to recover its costs any sooner. But it would rationalize the process, and it would allow over collected costs to be returned to ratepayers if the company is fortunate enough to avoid any major storms.[288]

8. The current system using occasional AAOs to allow Ameren Missouri to recover its extraordinary storm restoration costs requires Ameren Missouri to file an application for an AAO and to demonstrate that the storm event is extraordinary before related costs will be deferred through the AAO.[289] Staff is concerned that the burden of determining whether particular storm costs would be treated as normal or major would be shifted to Staff.[290]

9. However, Ameren Missouri's proposal would use the IEEE1366 method to determine whether a particular storm event would be classified as a major storm. That method looks at customer interruption minutes per customer to determine whether an outage event is outside the normal range of such events. Ameren Missouri would also treat as extraordinary costs and include in the two-way tracker the costs of preparation for an anticipated major storm that does not materialize if the non-internal labor O&M incurred for the preparation exceeds $1.5 million.[291]

10. The storm restoration costs tracker would not allow Ameren Missouri to automatically recover the tracked costs. Those costs would still be subject to a prudence

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[287] Transcript, Pages 1926-1927, Lines 9-25, 1-6.

[288] Wakeman Surrebuttal, Ex. 32, Page 3, Lines 3-8.

[289] Boateng Rebuttal, Ex. 207, Page 4, Lines 10-11.

[290] Boateng Surrebuttal, Ex. 231, Page 13, Lines 4-7.

[291] Wakeman Direct, Ex. 30, Pages 13-14, Lines 5-23, 1-4.

review by Staff just as those costs are currently reviewed for prudence.[292]

11. In general, the Commission remains skeptical of proposed tracking mechanisms. There is a legitimate concern that a tracker can reduce a company's incentive to aggressively control costs. However, that concern is reduced for major storm restoration costs. When faced with a massive power outage, the company's first priority must be to quickly restore electric service to its customers.

12. As explained by Ameren Missouri's witness, David Wakeman, who is the person in charge of its power restoration efforts, the ordinary means by which the company can control costs frequently are not available in major storm restoration situations. For example, the company cannot take the time to obtain competitive bids for services, it cannot limit the amount of overtime worked by its employees, nor can it decide not to hire outside restoration crews.[293] In any event, there is no evidence in the record to suggest that Ameren Missouri has spent money imprudently in past major storm restoration efforts.

13. Major storm restoration costs are particularly well suited for inclusion in a two-way tracker. Ameren Missouri has no control over whether major storms occur and has very little ability to control its restoration cost when such storms do hit its service territory. Such major storm costs can have a significant impact on the company's overall costs and ability to earn a reasonable return on its investment. Furthermore, for whatever reason, major storm events seem to have increased in frequency and intensity in recent years.

14. In the past, the Commission has allowed Ameren Missouri to recover all its major storm costs through a series of AAOs. The creation of a two-way tracker will simply rationalize that method of recovery without reducing Ameren Missouri's incentive to control

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[292] Transcript, Pages 1923-1924, Lines 22-25, 1-9.

[293] Wakeman Surrebuttal, Ex. 32, Page 4, Lines 15-22.

costs. It will not increase the burden of prudence review imposed on Staff and other parties. However, because it tracks major storm restoration costs both above and below the amount set in base rates, the tracker will return such costs to ratepayers if Ameren Missouri's service territory is not hit by a major storm. The Commission finds that a two-way tracker is appropriate in these circumstances and will approve the tracker proposed by Ameren Missouri.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The Commission approves the two-way tracker for major storm restoration costs as proposed by Ameren Missouri

14. Storm Costs:

A. If the Commission does not establish a two-way storm restoration costs tracker, then what is the appropriate amount to include in revenue requirement for major storm restoration costs?

B. If the Commission does establish a two-way storm restoration costs tracker, then what is the appropriate base level of major storm restoration Operations and Maintenance (O&M) costs to include in Ameren Missouri's revenue requirement?

Findings of Fact:

1. Having approved the major storm restoration cost tracker proposed by Ameren Missouri, the Commission must now decide what level of costs should be established as the base for that tracker.

2. All parties agree the base level should be established using a normalized storm restoration cost calculated by averaging storm costs incurred over a period of time.

Staff proposed to set that base amount at $6.8 million using a 60-month period ending on the true-up date of July 31, 2012.[294] Ameren Missouri accepted Staff's proposal.[295] MIEC initially argued the base level should be set at $6.5 million, using a 62-month period running from April 2007 to May 2012.[296] After the hearing, MIEC proposed the base level be set at $6.3 million by extending the averaged period to include June and July 2012, to reach the end of the true-up period.[297]

3. The difference between the parties is that MIEC claims the Commission should use a normalization period of a long as possible by including all available data, which in this case goes back to April 2007.[298]

4. The purpose of using a normalization to determine the proper amount of expense to include is rates is to find a representative period of time that will most accurately reflect what cost levels are likely to be incurred during the time rates will be in effect.[299]

5. In Ameren Missouri's last rate case, Ameren Missouri and Staff proposed to use 47 months of expense information as the normalization period, going back to April 2007 as the first month for which information was available. In that case, MIEC proposed to use expense information for only 23 months beginning with the start of the test-year and running through the end of the true-up period.[300] In rejecting MIEC's use of a 23-month

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[294] Transcript, Page 1916, Lines 16-21.

[295] Transcript, Pages 1902-1903, Lines 22-25, 1-4.

[296] Meyer Direct, Ex. 510, Page 10, lines 9-13.

[297] Transcript, Page 1903, Lines 12-25.

[298] Meyer Direct, Ex. 511, Page 8, Lines 9-14.

[299] Barnes Rebuttal, Ex. 12, Page 26, Lines 17-20.

[300] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order issued July 13, 2011, Page 21.

normalization period, the Commission indicated a longer period of normalization was likely to be more reliable than a shorter period of normalization.[301]

6. In this case, all parties recommend the use of an appropriately long period for the normalization. MIEC has apparently taken the Commission's statement in the last case to mean that normalization should be measured over as long a period as possible. In this case 64 months of available expense information is nearly the same period as the 60 months used by Staff and Ameren Missouri, although it has a $500,000 impact on the company's cost of service. However, in Ameren Missouri's next rate case, assuming the next case is filed in 15 months, there might be 79 months of available cost information. The case after that might have 94 months of available data. At some point, a principle of using all available data for the normalization period would become too long to be reliable.

7. The 60-month normalization period proposed by Staff and accepted by Ameren Missouri is a reasonable normalization period and the Commission will accept that normalization period to calculate Ameren Missouri's average major storm costs.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

The storm cost base shall be set using a 60-month average of $6.8 million.

15. Storm Assistance Revenues:

A. If the Commission authorizes a two-way storm restoration cost tracker for Ameren Missouri, should storm assistance revenues received from other utilities be included in the tracker or annualized and normalized and included as an offset in revenue requirement?

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[301] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order issued July 13, 2011, Page 22.

B. What amount of storm assistance revenue should be included in the cost of service?

Findings of Fact:

1. Storm assistance revenue is the amount of money Ameren Missouri receives to reimburse it for the labor costs associated with use of its crews for storm restoration work performed for other utilities around the country.[302] While this is not a regular source of income, Ameren Missouri reported receiving such revenue on eleven occasions since July 2005.[303]

2. Staff and MIEC propose that an annualized and normalized storm assistance revenue should be included as an offset to the base amount of storm restoration cost set in the tracker. Ameren Missouri would not use those revenues as an offset to the base amount set in the tracker, but would account for such revenue through the tracker as an offset to the restoration costs incurred by the company from storms in its own territory.[304]

3. The amount of storm assistance revenue Ameren Missouri receives can vary a great deal from year to year. In 2007, 2009, and 2010, the company received no such income, whereas in 2011, it received $2.6 million.[305]

4. Ameren Missouri has no control over such revenue as it depends entirely upon whether mutual assistance requests are received from some other utility.[306]

5. MIEC calculated that the company received $1.6 million in such revenue during the test year. It proposed to normalize that amount over two years to arrive at its

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[302] Wakeman Rebuttal, Ex. 31, Page 5, Lines 18-23.

[303] Meyer Direct, Ex. 510, Page 12, Lines 19-22.

[304] Wakeman Rebuttal, Ex. 31, Page 6, Lines 15-20.

[305] Transcript, Pages 1931-1932 and Ex. 76.

[306] Wakeman Direct, Ex. 30, Page 9, Lines 13-22.

$800,000 offset to revenue requirement for this case.[307]

6. Staff took a different approach to normalizing the amount of storm restoration revenue earned by Ameren Missouri. Staff noted that 2011, which happens to be the test year, contained an unusually high amount of storm restoration revenue. Staff proposed to normalize that level of income by averaging the amount of such income the company received over the five-year period ending July 31, 2012. That normalization resulted in Staff's recommendation to include $581,189 as an offset to the company's revenue requirement.[308]

7. Because this source of revenue is highly variable, Staff's five-year normalization provides a more reasonable estimate of likely future revenues than does the test-year normalization proposed by MIEC, which includes the unusually high revenues experienced in 2011 without acknowledging the earlier years when no such revenue was received.

8. The importance of this issue was diminished when the Commission decided to implement a two-way tracker for storm costs. Ameren Missouri will require the company to include these revenues within the tracker. The only question remaining is whether the $581,189 normalization of that revenue described by Staff should be used to reduce the base level of storm costs included in the tracker.

9. Ameren Missouri proposes that the revenue not be used to reduce the base level of storm costs, and would instead simply credit such revenues against expenses within the tracker. The Commission finds that to be a reasonable solution that will credit ratepayers for that revenue without imposing an economic penalty on the company if those

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[307] Meyer Direct, Ex. 510, Page 13, Lines 9-15.

[308] Transcript, Page 1928, Lines 20-25.

revenues are not received.

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

Ameren Missouri shall credit storm assistance revenue as an offset to major storm expenses within the two-way storm cost tracker established in the report and order. Such revenue shall not be used to reduce the base level of storm costs established within that tracker.

16. Vegetation Management and Infrastructure Inspection Tracker:

A. Should the unamortized balance for the regulatory asset associated with the Vegetation Management and Infrastructure Inspection Tracker be adjusted for all amortization through December 31, 2012, and amortized over two years?

B. Should the Vegetation Management and Infrastructure Inspection Tracker be continued?

Findings of Fact:

1. Ameren Missouri's vegetation management and infrastructure inspection expense is closely associated with two Commission rules. Following extensive storm related service outages in 2006, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution systems. Those rules, entitled Electrical Corporation Infrastructure Standards[309] and Electrical Corporation Vegetation Management Standards and Reporting Requirements,[310] became effective on June 30, 2008.

2. The rules establish specific standards requiring electric utilities to inspect and

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[309] Commission Rule 4 CSR 240-23.020.

[310] Commission Rule 4 CSR 240-23.030.

replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow a utility the means to recover the extra costs it incurs to comply with the requirements of the rule.

3. In an earlier rate case, ER-2008-0318, the Commission allowed Ameren Missouri to recover a set amount in its base rates for vegetation management and infrastructure inspection costs. However, since the rules were new, the Commission found that Ameren Missouri had too little experience to know how much it would need to spend to comply with the vegetation management and infrastructure inspection rules. Because of that uncertainty, the Commission established a two-way tracking mechanism to allow Ameren Missouri to track its vegetation management and infrastructure costs.

4. The order required Ameren Missouri to track actual expenditures around the base level. In any year in which Ameren Missouri spent below that base level, a regulatory liability would be created. In any year in which Ameren Missouri's spending exceeded the base level, a regulatory asset would be created. The regulatory assets and liabilities would be netted against each other and would be considered in a future rate case. The tracking mechanism contained a 10 percent cap so if Ameren Missouri's expenditures exceeded the base level by more than 10 percent it could not defer those costs under the tracking mechanism, but would need to apply for an additional accounting authority order. The Commission's order indicated that the tracking mechanism would operate until new rates

were established in Ameren Missouri's next rate case.[311]

5. The Commission renewed the tracking mechanism in Ameren Missouri's next two rate cases, ER-2010-0036 and ER-2011-0028, finding that Ameren Missouri's costs to comply with the vegetation management and infrastructure inspection rules were still uncertain, as the company had not yet completed a full four/six year vegetation management cycle on its entire system.[312]

6. Ameren Missouri asks that the tracker be continued. Staff does not oppose the continuation of the tracker, but MIEC contends the tracker is no longer necessary and urges the Commission to end it.

7. The other half of this issue concerns what should be done with the regulatory asset that has accumulated under the existing tracker. Ameren Missouri proposes that it be amortized and recovered over two years.[313] Staff argues for a three-year amortization.

8. Ameren Missouri has now been operating under the Commission's vegetation management and infrastructure inspection rules for nearly five years. Ameren Missouri has completed its first four-year cycle for vegetation management work on urban circuits under the requirements of the new rules, however, it will not complete the first six-year cycle of work on rural circuits until December 31, 2013.[314]

9. Ameren Missouri's actual expenditures for vegetation management and

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[311] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 48-49.

[312] *In the Matter of Union Electric Company, d/b/a Ameren UE's Tariffs to Increase its Annual Revenues for Electric Service, Report and Order*, File No. ER-2010-0036, May 28, 2010, and *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* Report and Order, File No. ER-2011-0028, July 13, 2011.

[313] Weiss Rebuttal, Ex.6, Pages 26-27.

[314] Wakeman Rebuttal, Ex. 31, Page 2, Lines 10-13.

infrastructure inspection have not been extremely volatile over the last three rate cases, but they have varied from base amounts. For example, the base amount allowed in rates in the last rate case was $52.2 million for vegetation management and $7.8 million for infrastructure inspections. The true-up expenditure amount for this case was $54.1 million on vegetation management and $6.2 million on infrastructure inspections.[315]

10. The tracking mechanism works in two directions. That means ratepayers can also benefit when, as was the case for infrastructure inspections in the last year, the company spent less than the established base amount.[316]

11. For the period of March 1, 2011, when rates went into effect in the last rate case, through July 31, 2012, the end of the true-up in this case, Ameren Missouri under-collected a net amount of $2,465,063. That represents a $2,896,420 under-collection for vegetation management, offset by an over-collection of $431,357 for infrastructure inspections.[317] In past Ameren Missouri rate cases the Commission has amortized that net amount over three years for collection from ratepayers and has rolled any unamortized balance from the previous tracker into the new amount so that only one tracker remains. Staff recommends the Commission do so again in this case.[318] Staff's proposed three-year amortization will increase Ameren Missouri's annual revenue requirement by $821,688.[319]

12. The Commission finds Staff's proposed treatment of the existing regulatory asset to be reasonable and consistent with past Commission practice.

Conclusions of Law:

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[315] Meyer Surrebuttal, Ex. 511, Charts at Pages 23-24.

[316] Barnes Rebuttal, Ex. 12, Page 38, Lines 12-13.

[317] Grissum Surrebuttal, Ex. 223, Page 7, Lines 12-17.

[318] Staff Report Revenue Requirement Cost of Service, Ex. 202, Pages 114-115.

[319] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 115, Lines 26-28.

A. Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including Ameren Missouri, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

B. Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates … .

C. Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including Ameren Missouri, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that allows Ameren Missouri to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[320]

Decision:

Although Ameren Missouri now has more experience in complying with the rules, it

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[320] Commission Rule 4 CSR 240-23.030(10).

still has not completed a single cycle on inspections for its rural circuits. The Commission finds that because of that remaining uncertainty the tracker is still needed. However, as the Commission has indicated in previous rate cases, it does not intend for this tracker to become permanent. For this case, the Commission will renew the existing vegetation management and infrastructure inspection tracker.

Ameren Missouri shall establish a tracking mechanism to track future vegetation management and infrastructure costs. That tracking mechanism shall include a base level of $60.3 million ($54.1 million vegetation management + $6.2 million infrastructure = $60.3 million). Actual expenditures shall be tracked around that base level with the creation of a regulatory liability in any year where Ameren Missouri spends less than the base amount and a regulatory asset in any year where Ameren Missouri spends more than the base amount. The assets and liabilities shall be netted against each other and shall be considered in Ameren Missouri's next rate case. The tracking mechanism shall contain a ten percent cap so expenditures exceeding the base level by more than ten percent shall not be deferred under the tracking mechanism. If Ameren Missouri's vegetation management and infrastructure inspection costs exceed the ten percent cap, it may request additional accounting authority from the Commission in a separate proceeding. The tracking mechanism shall operate until the Commission establishes new rates in Ameren Missouri's next rate case.

The net under-collection of $2,465,063 under the tracker established in Case No. ER-2011-0028 shall be combined with any unamortized amount related to the tracker established in Case No. ER-2010-0036 and then amortized over a three-year period so that only one tracker remains.

17. Rate Design:

A. What should the residential class customer charge be?

B. What should the small general service class customer charge be (single-phase and three-phase)?

Findings of Fact:

1. After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among Ameren Missouri's customer classes. The basic principle guiding that decision is that the customer class that causes a cost should pay that cost.

2. The Commission has approved a stipulation and agreement that resolves most of the rate design issues. One issue that remains unresolved is amount of Ameren Missouri's customer charge for its residential and small general services customer classes.

3. The customer charge is the set amount on every customer's bill that must be paid even if the customer uses no electricity.

4. Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of how much electricity the customer uses.[321] Customer-related costs are generally recovered through the customer charge while other costs are recovered through volumetric rates that vary with the amount of electricity used.

5. It is important to remember that determining an appropriate customer charge is a question of rate design, not a question of the company's revenue requirement. That means any increase in the company's customer charge would be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of

[321] Cooper Direct, Ex. 36, Page 9, Lines 20-23.

revenue.

6. In actual practice, because the amount collected from volumetric rates varies with the amount of electricity used, the company will collect less money from volumetric rates when customers use less electricity. Thus, for example, in a cool summer, when customers are using less air conditioning, the company runs the risk of collecting less revenue. For that reason, electric utilities prefer to lessen risk by collecting more of its charges through the fixed customer charge.

7. Ameren Missouri's current customer charge for residential customers is set at $8.00 per month. For the small general service rate, the current customer charge is $9.74 per month for single-phase service and $19.49 for three-phase service. Ameren Missouri proposes to increase those customer charges to $12.00 per month for residential customers. It would increase the customer charge to $14.61 for single-phase customers and $29.24 for three-phase customers in the small general service class.[322]

8. Staff would slightly increase the residential customer charges to $9.00,[323] but NRDC, Public Counsel, and AARP/Consumers Council oppose any increase in the customer charges.

9. Ameren Missouri, Staff, and Public Counsel all submitted cost of service studies that support their positions regarding the customer charges. Ameren Missouri's study indicates a customer charge of $20.00 would be appropriate for the residential class, although the company limited its request to $12.00.[324] Staff's study indicated the correct amount for the residential customer charge would be $8.97, which Staff rounded to

[322] Cooper Direct, Ex. 36, Pages 21-22, Lines 16-25, 1-5. The small general services class includes small commercial businesses.

[323] Staff's Rate Design and Class Cost of Service Report, Ex. 205, Page 22, Lines 17-18.

[324] Cooper Direct, Ex. 36, Page 21, Lines 16-21.

$9.00.[325] Public Counsel's study indicated the correct customer charge would be under $6.00 for the residential class and about $10.65 for the small general services class. Public Counsel recommends the current customer charges be unchanged.[326]

10. The chief difference between the various cost of service studies is the amount of distribution plant that each expert assigned to customer-related usage. Ameren Missouri's study tends to overstate the amount of the distribution system that would appropriately be allocated to customer-related usage.[327] On that basis, for this purpose, the Commission finds the cost of service studies submitted by Staff and Public Counsel to be more reliable.

11. Regardless of their details, the Commission is not bound to set the customer charges based solely on the details of the cost of service studies. The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges.

12. Recently, in File Number EO-2012-0142, the Commission approved Ameren Missouri's first energy efficiency plan under the Missouri Energy Efficiency Investment Act. (MEEIA). Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity.[328]

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[325] Transcript, Page 2148, Lines 20-24.

[326] Meisenheimer Direct, Ex. 403, Page 17, Lines 11-16.

[327] Transcript, Page 2067-2071 and Ex. 410.

[328] Morgan Rebuttal, Ex. 650, Page 7, Lines 11-15.

13. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small,[329] but increasing customer charges at this time would send exactly to wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.

14. The Commission finds that the existing customer charges for the residential and small general services classes should not be increased.

Conclusions of Law:

A. The Missouri Energy Efficiency Investment Act is codified at Section 393.1075, RSMo (Supp. 2011).

Decision:

Ameren Missouri's customer charges for residential and small general services customers shall remain unchanged.

B. Should the Commission address declining block rate design either by opening a separate docket on rate design or by ordering Ameren to address the rate design in its next general rate case?

Findings of Fact:

1. Ameren Missouri's current residential rate design includes a declining block element for the winter billing season only. That means that during the winter the rate paid for electricity goes down as more electricity is used. That declining block design benefits customer who use a lot of electricity in the winter, chiefly customers who use electricity for space heating in their home. That design also benefits the electric utility in that it makes electricity more competitive with other fuel sources for space heating and allows the company to sell more electricity during off-peak times. The downside of a declining block

[329] Davis Surrebuttal, Ex. 40, Page 3, Lines 12-19.

rate design is that it may not send a proper price signal and tends to encourage the excessive consumption of electricity.[330]

2. In Ameren Missouri's last rate case, the Commission decided not to eliminate Ameren Missouri's declining block rates because not enough evidence was presented in that case to justify such a modification. At that time, the Commission invited the parties to present more evidence in the next rate case.[331]

3. The NRDC raised the issue of declining block rates again in this case through the testimony of Pamela Morgan. Ms. Morgan's testimony acknowledged the complexity of the issue and indicated much of the information needed to properly evaluate the continued use of declining block rates is controlled by the utility. She recommends the Commission open a new, separate investigative case to address this issue.[332]

4. Ameren Missouri agreed that if the Commission wished to investigate declining block rates it should do so in the context of a broader investigative case that could involve all Missouri's regulated electric utilities and all interested stakeholders, not just those who have intervened in this case.[333]

Conclusions of Law:

There are no additional conclusions of law for this issue.

Decision:

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[330] Morgan Rebuttal, Ex. 650, Page 17, Lines 5-7.

[331] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service*, File No. ER-2011-0028, Report and Order, issued July 13, 2011, Page 124.

[332] Morgan Rebuttal, Ex. 650, Page 18, Lines 10-13.

[333] Cooper Surrebuttal, Ex. 38, Pages 14-15, Lines 14-23, 1-5.

The Commission finds that the issue of whether declining block rates should be eliminated or modified should be addressed in an investigative case outside the confines of this rate case. The Commission will open such a case by separate order.

18. Should the Commission make the Findings Required by the Energy Independence and Security Act of 2007 (EISA).

Findings of Fact:

1. In 2007, the United States Congress passed the Energy Independence and Security Act of 2007 (EISA). EISA amended the Public Utility Regulatory Policies Act of 1978 (PURPA) to establish four additional PURPA standards with which each electric utility must comply. Those four new standards relate to 1) Integrated Resource Planning (IRP), 2) Rate Design Modifications to Promote Energy Efficiency Investments, 3) Consideration of Smart Grid Investments, and 4) Smart Grid Information. EISA requires the Commission to consider in a general rate case for each individual electric utility whether it is appropriate to implement those standards to encourage conservation of electric energy, efficiency in the use of facilities and resources by electric utilities, and equitable rates to consumers of electricity. [334]

2. In its direct testimony, Staff examined Ameren Missouri's compliance with each of the EISA standards and concluded that the Commission should make a specific finding that the Commission and the Company do not need to do anything further to comply with each of those standards. No party responded to Staff's testimony, either in testimony or by argument.

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[334] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 176, Lines 9-26.

3. PURPA section 111(d)(16)[335] requires state commissions to consider integration of energy resources into utility, state and regional plans and to adopt policies to establish cost-effective energy efficiency as a priority resource.[336]

4. The Commission has complied with that standard by revising its integrated resource planning rule to require the screening and integration of cost-effective energy efficiency resources as part of the resource planning process.

5. PURPA section 111(d)(17)[337] requires state commissions to consider various means to encourage energy efficiency.[338]

6. The Commission has complied with that standard by implementing the requirements of the Missouri Energy Efficiency Investment Act (MEEIA) in this case and through a stipulation and agreement resolving Ameren Missouri's MEEIA implementation filing in File No. EO-2012-0142.[339]

7. PURPA section 111(d)(18)[340] requires state commissions to consider requiring electric utilities to consider investments in smart grid technology before investing in non-advanced grid technologies. PURPA section 111(d)(19)[341] requires state commissions to make available information about smart grid technology.

8. The Commission has taken steps to encourage electric utilities to become

[335] This section is codified at 16 U.S.C.A. Section 2621(d)(16).

[336] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 178, Lines 20-26.

[337] This section is codified at 16 U.S.C.A. Section 2621(d)(17).

[338] Staff Report Revenue Requirement Cost of Service, Ex. 202, Pages 179-180, Lines 25-28, 1-5.

[339] Staff Report Revenue Requirement Cost of Service, Ex. 202, Pages 180-181.

[340] This section is codified at 16 U.S.C.A. Section 2621(d)(18).

[341] This section is codified at 16 U.S.C.A. Section 2621(d)(19).

familiar with and to use smart grid technology.[342]

Conclusions of Law:

A. The purpose of PURPA is to encourage

(1) conservation of energy supplied by electric utilities;
(2) the optimization of the efficiency of use of facilities and resources by electric utilities; and
(3) equitable rates to electric consumers.[343]

B. The four new PURPA standards created by the Energy Independence and Security Act of 2007 (EISA) are:

(16) Integrated resource planning
Each electric utility shall—
(A) integrate energy efficiency resources into utility, State, and regional plans; and
(B) adopt policies establishing cost-effective energy efficiency as a priority resource.
(17) Rate design modifications to promote energy efficiency investments
(A) In general
The rates allowed to be charged by any electric utility shall—
(i) align utility incentives with the delivery of cost-effective energy efficiency; and
(ii) promote energy efficiency investments.
(B) Policy options
In complying with subparagraph (A) each State regulatory authority and each nonregulated utility shall consider—
(i) removing the throughput incentive and other regulatory and management disincentives to energy efficiency;
(ii) providing utility incentives for the successful management of energy efficiency programs;
(iii) including the impact on adoption of energy efficiency as 1 of the goals of retail rate design, recognizing that energy efficiency must be balanced with other objectives;
(iv) adopting rate designs that encourage energy efficiency for each customer class;
(v) allowing timely recovery of energy efficiency-related costs; and
(vi) offering home energy audits, offering demand response programs, publicizing the financial and environmental benefits associated with making home energy efficiency improvements,

[342] Staff Report Revenue Requirement Cost of Service, Ex. 202, Pages 181-182.

[343] 16 U.S.C.A. Section 2611.

and educating homeowners about all existing Federal and State incentives, including the availability of low-cost loans, that make energy efficiency improvements more affordable.

(18) Consideration of smart grid investments

(A) In general

Each State shall consider requiring that, prior to undertaking investments in nonadvanced grid technologies, an electric utility of the State demonstrate to the State that the electric utility considered an investment in a qualified smart grid system based on appropriate factors, including—

(i) total costs;
(ii) cost-effectiveness;
(iii) improved reliability;
(iv) security;
(v) system performance; and
(vi) societal benefit.

(B) Rate recovery

Each State shall consider authorizing each electric utility of the State to recover from ratepayers any capital, operating expenditure, or other costs of the electric utility relating to the deployment of a qualified smart grid system, including a reasonable rate of return on capital expenditures of the electric utility for the deployment of the qualified smart grid system.

(C) Obsolete equipment

Each State shall consider authorizing any electric utility or other party of the State to deploy a qualified smart grid system to recover in a timely manner the remaining book-value costs of any equipment rendered obsolete by the deployment of the qualified smart grid system, based on the remaining depreciable life of the obsolete equipment.

(19) Smart Grid information

(A) Standard

All electricity purchasers shall be provided direct access, in written or electronic machine-readable form as appropriate, to information from their electricity provider as provided in subparagraph (B)

(B) Information

Information provided under this section, to the extent practicable, shall include:

(i) Prices

Purchasers and other interested persons shall be provided with information on—

(I) time-based electricity prices in the wholesale electricity market; and
(II) time-based electricity retail prices or rates that are available to the purchasers.

(ii) Usage

Purchasers shall be provided with the number of electricity units, expressed in kwh, purchased by them

(iii) Intervals and projections

Updates of information on prices and usage shall be offered on not less than a daily basis, shall include hourly price and use information, where available, and shall include a day-ahead projection of such price information to the extent available.

(iv) Sources

Purchasers and other interested persons shall be provided annually with written information on the sources of the power provided by the utility, to the extent it can be determined, by type of generation, including greenhouse gas emissions associated with each type of generation, for intervals during which such information is available on a cost-effective basis.

(C) Access

Purchasers shall be able to access their own information at any time through the Internet and on other means of communication elected by that utility for Smart Grid applications. Other interested persons shall be able to access information not specific to any purchaser through the Internet. Information specific to any purchaser shall be provided solely to that purchaser.[344]

Decision:

While not specifically making a determination to implement PURPA section 111(d)(16), the Commission has promulgated rules to address the principles of that section. Therefore, nothing remains for the Commission to determine in response to PURPA section 111(d)(16).

No further determination by the Commission is needed in response to PURPA section 111(d)(17).

The Commission has established the appropriate avenues for monitoring smart grid activities and no greater ongoing activity is needed in response to PURPA sections 111(d)(18) and 111(d)(19).

Application for Waiver or Variance of 4 CSR 240-20.100(6)(A)16 for Maryland Heights

[344] 16 U.S.C.A. 2621(d)(16)-(19).

Landfill Gas Facility:

On December 7, 2012, Ameren Missouri filed an application asking the Commission for a waiver or variance from Commission Rule 4 CSR 240-20.100(6)(A)16 concerning the treatment of landfill gas purchased from the landfill owner for operation of the company's Maryland Heights landfill gas facility. That regulation provides that RES compliance costs may only be recovered through a RESRAM or as part of a general rate proceeding. Such costs may not be recovered through a fuel adjustment clause.

In recent days, a question has arisen as to whether some or all of the cost of landfill gas purchased from the owner of the landfill and used to operate the company's Maryland Heights landfill gas facility is a RES compliance cost. The parties to this case assumed that the cost of such gas would be recovered through the fuel adjustment clause. The treatment of these landfill gas costs would have a very small impact on this case, but recalculating many of the agreed upon particulars of the fuel adjustment clause at this late date would be difficult.

Because of those difficulties, Ameren Missouri asks the Commission to grant it a waiver from the rule provision to allow it to continue to flow the cost of the landfill gas through its fuel adjustment clause. Ameren Missouri agrees that in the future it will work with Staff and other interested parties to resolve the issues surrounding the landfill gas. The application represents that Staff supports the company's request for waiver of the rule provision. It also represents that Ameren Missouri has contacted all other parties to this case and that none of them object to the application.

On December 7, the Commission issued an order establishing December 11 as the deadline for any interested party to respond to Ameren Missouri's application. Staff responded on December 11, indicating its support for the requested waiver for purposes of this case only. No other response has been filed.

The Commission finds Ameren Missouri's application to be reasonable and will waive application of the rule provision as requested.

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a Ameren Missouri on February 3, 2012, and assigned tariff number YE-2012-0370, are rejected.

2. Union Electric Company, d/b/a Ameren Missouri is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order. Ameren Missouri shall file its compliance tariff no later than December 18, 2012.

3. Union Electric Company, d/b/a Ameren Missouri shall file the information required by Section 393.275.1, RSMo 2000, and Commission Rule 4 CSR 240-10.060 no later than January 14, 2013.

4. For purpose of the rates established in this case, Ameren Missouri is granted a waiver of Commission Rule 4 CSR 240-20.100(6)(A)16 as regards the purchase of landfill gas for the operation of the Maryland Heights Landfill Gas Facility.

5. This report and order shall become effective on December 22, 2012.

BY THE COMMISSION

(S E A L)

Steven C. Reed
Secretary

Gunn, Chm., concurs with concurring opinion attached;
Jarrett, C., concurs with concurring opinion to follow;
Stoll, C., concurs; and
Kenney, C., dissents, with dissenting opinion to follow.
and certify compliance with the provisions of Section 536.080, RSMo.

Dated at Jefferson City, Missouri,
on this 12th day of December, 2012.

BEFORE THE WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER AND LIGHT COMPANY, Respondent.	**DOCKET UE-111190** **SETTLEMENT STIPULATION**

1 As described below, all parties to this docket, *i.e.,* PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or the Company), Staff of the Washington Utilities and Transportation Commission (Staff), the Public Counsel Section of the Office of the Attorney General (Public Counsel), the Industrial Customers of Northwest Utilities (ICNU), and The Energy Project[1] (individually, Party; collectively, Parties) have reached an agreed resolution of issues in this docket, subject to Commission approval.[2] Consequently, this Settlement Stipulation (Stipulation) is being filed with the Commission as a "full settlement" pursuant to WAC 480-07-730(1). The Stipulation consists of this document, entitled "Settlement Stipulation," and Appendices A, B, and C.

[1] Comprised of The Energy Project, Opportunity Council, Northwest Community Action Center, and Industrialization Center of Washington.
[2] The International Brotherhood of Electrical Workers (IBEW Local 125) was required by the Commission to coordinate its participation with Staff and Public Counsel. Staff and Public Counsel support this resolution and IBEW Local 125 has not expressed a separate position.

2 The Parties understand that this Stipulation is not binding on the Commission or any Party unless and until the Commission approves it.[3]

I. PARTIES

3 The parties to the Stipulation in this docket are PacifiCorp, Staff, Public Counsel, ICNU, and The Energy Project.

II. RECITALS

4 On July 1, 2011, PacifiCorp filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariff WN U-75, designed to effect a general rate increase for electric service. In the filing, the Company requested a revenue increase of $12.9 million, or 4.3 percent.

5 The filing was based on an historical twelve-month period ended December 31, 2010, with limited restating and pro forma adjustments. In particular, net power costs reflected the normalized pro forma costs for the 12-month period ending May 31, 2013, the rate effective period in this case, scaled back to the historic test period using the production factor.[4] The Commission suspended the filing and approved commencement of discovery in Order 01, dated July 28, 2011.[5] By an order dated August 12, 2011, presiding Administrative Law Judge (ALJ) Patricia Clark granted the petition to intervene of ICNU.[6] At the Prehearing Conference on August 23, 2011, The Energy Project was also granted intervention in this proceeding.[7] By an order dated October 28,

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[3] The exception is that prior to the Commission's approval of the Stipulation, the Parties agree to support the Stipulation before the Commission. Section III, Paragraph K.4, *infra*.
[4] The production factor is the ratio of the loads in the historic test period to the loads in the forecast period.
[5] *Wash. Utilities and Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-111190, Order 01 (July 28, 2011).
[6] *Wash. Utilities and Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-111190, Order 03 (Aug. 12, 2011).
[7] *Wash. Utilities and Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-111190, Order 04 (Aug. 31, 2011).

2011, ALJ Clark granted the petition to intervene of IBEW Local 125 subject to conditions.[8]

6 Pursuant to Order 01, Staff, Public Counsel, and ICNU conducted extensive discovery on the Company's direct testimony. The Parties gathered for an initial settlement conference on November 18, 2011. The Parties did not agree to settle this case in their initial discussions.

7 Staff, Public Counsel, ICNU and the Energy Project filed Responsive Testimony on January 6, 2012. Staff filed testimony on policy, various revenue requirement issues, net power costs, cost of service and rate design, and low-income issues. Staff recommended a revenue requirement increase of $3.3 million. Public Counsel filed testimony on selected revenue requirement issues, recommending adjustments of $3.1 million. ICNU filed testimony on revenue requirement issues and net power costs, recommending adjustments of $3.7 million and $10.1 million, respectively. The Energy Project filed testimony supporting a plan to resolve the low-income issues raised in this case, a plan also outlined in the testimony of Staff.

8 The Parties participated in a second settlement conference on February 1, 2012, facilitated by Settlement Judge Gregory J. Kopta. At the settlement conference, the Parties presented proposals and counter-proposals culminating in an agreement to a comprehensive settlement of this case.

9 The Parties have reached an agreed resolution of this proceeding, set forth in the following Stipulation, which is entered into by the Parties voluntarily to resolve matters in dispute among them in the interests of expediting the orderly disposition of this

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[8] *Wash. Utilities and Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket UE-111190, Order 05 (Oct. 28, 2011).

proceeding. The Parties intend to file the Stipulation with the Commission and request Commission approval of the Stipulation.

III. AGREEMENT

A. Rate Increase and Rate Effective Date

10 The Parties agree that PacifiCorp shall be authorized to implement rate changes designed to increase its annual revenues from Washington customers by $4.5 million (or 1.5 percent). The Parties agree that the rate changes identified herein will be effective with service on and after June 1, 2012. The suspension period in this case ends on May 31, 2012. As shown in Appendix A and detailed below, the Parties agree that the proposed $4.5 million rate increase reflects specific updates and adjustments to the Company's filed case, as well as an additional non-specific adjustment related to a compromise of issues on which resolution could not be reached. Below is the agreement on specific items reflected in the Company's revenue requirement. While certain adjustments were specifically addressed in the settlement, they are being accepted only as part of a comprehensive settlement stipulation that resolves all issues associated with the Company's original filing. As such, they should be viewed in the broader context of the total settlement stipulation. The Parties agree that costs and revenues will not be subject to further updates under this Stipulation.

11 **1) <u>Net Power Cost Update</u>**

This update includes a decrease in revenue requirement associated with net power costs of $2.9 million to reflect updates supplied by the Company in discovery in December 2011. This net power cost update is consistent with Commission practice in prior cases, except as discussed in item Section III, Paragraph A.7 below. These updates and the adjustment in Section III, Paragraph A.7 produce west control area net power costs of $548.6 million and Washington allocated net power costs of $124.0 million.

12 **2) Ancillary Service Revenue (Seattle City Light) Update**

This update includes an increase in ancillary service revenues in connection with the Company's new contract with Seattle City Light. This update reduces the revenue requirement by $2.2 million.

13 **3) Non-Recurring Demand Side Management ("DSM") Expense Correction**

This adjustment reduces revenue requirement by $68,064 for certain DSM expenses that should have been booked to the DSM balancing account.

14 **4) Legal and Litigation Expense**

This adjustment reduces revenue requirement by $16,633 for legal and litigation expenses that are more appropriately allocated to states other than Washington or below the line.

15 **5) Self Insurance**

This adjustment rejects the Company's proposal for "Self Insurance" through establishment of a reserve account and adopts a six-year average of actual damage expenses. The total settlement adjustment reduces revenue requirement by $384,381.

16 **6) Administrative and General Expenses**

The settling parties have agreed to remove the following administrative and general costs:

(a) Advertising costs: This adjustment removes certain advertising costs that should have been allocated to other states or booked below the line. Settlement adjustment of $1,268.

(b) Memberships and Subscriptions Expense: This adjustment removes certain dues that were either more appropriately allocated to other states or below the line. Settlement adjustment of $16,721.

(c) Directors' and Officers' Insurance: This adjustment removes 100 percent of directors' and officers' insurance from the test year. Settlement adjustment of $23,535.

(d) Meals/Legislative/Charitable Expenses: This adjustment removes certain legislative, charitable and employee meal costs. Settlement adjustment of $4,420.

17 **7) <u>Net Power Cost Expense</u>**

This adjustment rejects the Company's proposal to update coal costs which reduces revenue requirement by $1,490,583.

18 **8) <u>Miscellaneous Rate Base</u>**

This adjustment removes from rate base the prepaid asset associated with Chehalis maintenance costs. This adjustment reduces revenue requirement by $114,054.

19 **9) <u>Production Factor</u>**

This adjustment recalculates the production factor to account for changes to new power cost components. This adjustment increases revenue requirement by $77,316.

20 **10) <u>Interest True-Up</u>**

This adjustment provides a true up for interest costs based on other adjustments included in the settlement revenue requirement. This adjustment increases revenue requirement by $13,842.

21 **11) <u>Miscellaneous Settlement Adjustment</u>**

In addition to specific updates and adjustments, the Parties agree to an additional $1.2 million decrease to revenue requirement.

The Company's initial filing did not propose any change to the Company's cost of capital determined in Order 06 in Docket UE-100749 other than an update to reduce the Company's cost of debt from 5.89 percent to 5.76 percent and an associated reduction in the overall rate of return from 7.81 percent to 7.74 percent.[9] No Party objected to this approach to cost of capital in responsive testimony. Therefore, the Parties agree that for ratemaking purposes in Washington, the Company's capital structure and return on equity from Docket UE-100749 remains unchanged, while the Company's cost of debt and overall rate of return have been updated as noted.

22 There are numerous adjustments identified by the non-Company parties which are not specifically addressed by this Stipulation. Parties are free to raise these and any other issue in the Company's next rate case.

B. Rate Spread

23 The Parties agree that the increase will be spread to all rate schedules, other than street lighting, on an equal percentage of revenue basis. Street lighting schedules will receive no increase. Appendix B to this Stipulation shows the results of the agreed rate spread by rate schedule.

C. Rate Design

24 The Parties agree to request that the Commission accept the Company's rate design proposal that applies an equal percentage increase to all billing elements as set forth in the Company's direct testimony in this proceeding[10] with one exception: the residential basic charge will remain at $6.00 per month.[11] Appendix B demonstrates this rate design, shows the monthly impact of the rate change on residential customers, and contains the

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[9] Williams, Exh. No.____ (BNW-1T) at 2-3.
[10] Griffith, Exh. No. ___ (WRG-1T) at 3-5.
[11] Schedule 16 Residential Service and Schedule 17 Low Income Bill Assistance Program – Residential Service.

workpapers reflecting the rates designed to collect the $4.5 million rate increase. Appendix C contains the proposed tariff schedules designed to collect the $4.5 million rate increase.

D. Low Income Bill Assistance

25 The Parties agree to accept a proposal by Staff and the Energy Project for a five-year plan to gradually increase aspects of the Low-Income Bill Assistance Program, as described in the testimony of Staff witness Deborah J. Reynolds[12] and Energy Project witness Charles Eberdt[13] ("Five-Year LIBA Plan"). The key elements of the Five-Year LIBA Plan are the following:

- Certify a share of the client population to be eligible for a two year period. Beginning in 2012, ten percent of clients will be certified as eligible for a two-year period, and in each of the following three program years, an additional five percent of clients will be certified for two years up to 25 percent in 2015. Up to 40 percent of the customers participating in 2016 will be in some phase of two-year participation.
- Increase agency funding for each client certification to $65.00 following approval of this Stipulation, with additional increases of $2.50 each program year after 2012 up to $75.00 in 2016.[14]
- Increase the average benefit to low income bill assistance recipients by 10 percent following approval of this Stipulation, with additional increases to the average benefit of two times the percentage increase of any future residential general rate increase between 2013 and 2016.

[12] Reynolds, Exh. No. ___ (DJR-1T) at 13-19 and Exh. No.___(DJR-3).
[13] Eberdt, Exh. No. ___ (CME-1T) and Exh. No. ___ (CME-3).
[14] Reynolds, Exh. No. ___(DJR-3), Column B.

- Under this Stipulation, the residential surcharge in Schedule 91 will increase from \$0.55 to \$0.63 per month when new rates go into effect. Thereafter, absent a pending general rate case filing, the Company will file for an increase to the Schedule 91 monthly surcharge around May 1 of each year to reflect the increased funding requirements specified in this Stipulation. The proposed increases to the Schedule 91 monthly surcharges will be applied on an equal percentage basis to all rate schedules. The Parties agree that the Company's Schedule 91 filings under the Five-Year LIBA Plan will be limited in scope to implementing the Plan.
- Appendix B demonstrates the rates associated with implementation of the Five-Year LIBA Plan in this case.

26 The Parties agree that the Five-Year LIBA Plan resolves all Low Income Bill Assistance Program issues among the Parties through the duration of the Plan. The Parties agree to support or not oppose the changes to the Low-Income Bill Assistance Program in the Five-Year LIBA Plan, as long as the changes are consistent with this Stipulation. In particular, the Parties agree to support the Company's annual May Schedule 91 filings outside of a general rate case, and the Schedule 17 and 91 or other tariff filings necessary to increase the surcharge within a general rate case, as necessary to implement the Five-Year LIBA Plan.[15] Proposed Schedule 17 and Schedule 91 are included in the proposed tariffs contained in Appendix C of this Stipulation to become effective with service on and after June 1, 2012. Proposed Schedule 17 reflects the new levels for the rate discounts as reflected in the "Low Income Credits" sheet of Appendix B. Proposed

[15] There are a number of moving pieces which may affect the need for increased or decreased bill assistance in a given year, such as customer growth, the health of the economy and federal funding for energy assistance. This proposal is intended to free parties from the need to file testimony about LIBA in each general rate case between now and 2016. In the event of a substantial change of circumstances, any party may make an alternative low income proposal, pursuant to RCW 80.28.060.

Schedule 17, Revised Sheet No. 17.2, has been revised to indicate that 4720 customers is the maximum number of customers who will be *certified* to participate in a given program year, rather than the maximum number of customers who will be allowed to participate in a given program year as is currently the case. The subsequent May filings will indicate the beginning of the next program year.

E. Next General Rate Case and Post-Stipulation Collaborative Process

27 The Company agrees that it will not file a general rate case before January 1, 2013. This provision does not preclude the Company from filing requests for deferred accounting or other accounting petitions before January 1, 2013. If such filings are made by the Company, the non-Company Parties are free to take any position they deem appropriate, including opposition to such requests.

28 In consideration of the Company's agreement to delay its next general rate case filing, the Parties agree to engage in a collaborative process to review the issues listed in this Paragraph. The Parties agree to work cooperatively to ensure that this process is substantively complete by November 1, 2012, to allow the results to be incorporated into the Company's next general rate case filing. This process does not require Parties to reach agreement and there may be issues that ultimately require Commission resolution. Within 30 days of the issuance of the Commission order approving this Stipulation, the Parties agree to establish milestones to meet this schedule. If the agreed-to milestones are not met or the collaborative process ceases, the Company may raise its concerns to the Commission and may request appointment of an administrative law judge to facilitate the collaborative process. The Parties agree this collaborative process will:

- Consider methods to streamline the regulatory process;

- Evaluate options for an equitable and balanced power cost adjustment mechanism;
- Evaluate the West Control Area inter-jurisdictional allocation methodology and consider alternative options;
- Consider alternative test period conventions;
- Consider alternatives to the application of the production factor;
- Consider the content of and approach to attrition studies;
- Evaluate the AURORA power cost dispatch model for use in PacifiCorp's future Washington general rate cases or other net power cost filings where the Company currently relies upon the GRID power cost dispatch model; and
- If necessary, review the Company's approach to modeling market caps for potential alternate approaches or modeling refinements.

F. West Control Area Inter-jurisdictional Allocation Methodology Review

29 In Docket UE-060817, the Commission required a review of the West Control Area inter-jurisdictional allocation methodology after five years. In footnote 444 of Order 06 in Docket UE-100749, the Commission noted that this review was due in approximately June 2012. The Parties agree to conduct this review as a part of the collaborative process outlined in paragraph E, with PacifiCorp filing the results in its next rate case filing. As a part of the Commission's approval of this Stipulation, the Parties ask the Commission to extend the date on which the review filing is due until January 2013.

G. Renewable Energy Credit Revenues

30 This Stipulation does not contain renewable energy credit (REC) revenues. In Phase 2 of Docket UE-100749, the Commission is considering the proper rate treatment of

PacifiCorp's REC revenues for periods subsequent to January 1, 2009, including 2010 REC revenues. This Stipulation does not preclude any Party from seeking clarification or reconsideration in Docket UE-100749 of whether the Commission's order in that docket would allow customers to receive some or all of the 2010 REC revenues in Docket UE-111190. If the Commission's final order in Phase 2 of Docket UE-100749 or order on clarification or reconsideration directs or allows further litigation on the disposition of the Company's 2010 REC revenues in Docket UE-111190, Parties may raise this issue in Docket UE-111190 consistent with that order. The Parties agree that this provision does not preclude Parties from otherwise seeking reconsideration, clarification or judicial review in Docket UE-100749. Except as identified above, the Parties further agree that no other issues related to REC revenues are resolved by this Stipulation.

H. Property and Liability Insurance Expense

31 PacifiCorp agrees that it will not implement its self insurance proposal to establish a reserve account related to property insurance expense as proposed in its direct testimony in this case.[16] The Parties agree to instead calculate property and liability expense in this and future proceedings using a six-year average of actual damage expenses. The Parties agree that PacifiCorp may file for deferred accounting of extraordinary claims, if any.

I. Executive Compensation Report

32 PacifiCorp agrees to work with Public Counsel, and other Parties if requested, to develop a report on executive compensation practices and accounting that includes at a minimum the following information which the Commission required of Avista Corporation in Order 06 in Dockets UE-110876 and UG-110877:

[16] Dalley, Exh. No. ___ (RBD-1T) at 16-20.

- A description of current executive compensation, including but not limited to base salary, non-equity incentive pay, and incentive pay. This description should state what elements and amounts are included in rates for the Company and what elements and amounts are not recovered through rates.

- A description of how levels of executive compensation are set. This description should include discussion of the basis for selecting ostensibly comparable utilities that were surveyed, state what those survey results showed, and explain how the results relate to PacifiCorp. PacifiCorp is also required to state whether executive compensation paid by any Pacific Northwest investor-owned (e.g., Puget Sound Energy, Avista, et cetera) or publicly-owned utilities (e.g., Seattle City Light, Tacoma Power, Public Utility District No. 1 of Snohomish County, and the Bonneville Power Administration) were considered and, if not, explain why not.

- A discussion of PacifiCorp's perspective on whether and, if so, why, the existing levels of executive compensation are appropriate for recovery in utility rates.

33 PacifiCorp will provide the report to Parties no later than 30 days prior to the filing of its next general rate case. The Parties agree to enter into a standard Confidentiality Agreement with PacifiCorp for this purpose if the report includes confidential employee information.

J. Discovery and Procedural Schedule

34 The Parties agree to suspend all discovery in this proceeding pending filing and consideration of this Stipulation. In the event the case resumes, the Parties agree to work cooperatively to develop a new schedule taking into consideration the delay associated with this settlement.

K. General Provisions

35 **1.** The Parties agree that this Stipulation is in the public interest and would produce rates for the Company that are fair, just, reasonable, and sufficient. The Parties agree to support this Stipulation as a settlement of all contested issues in this proceeding, except issues related to REC revenues as identified in Paragraph G. The Parties further agree that this Stipulation, upon its approval by the Commission, resolves and concludes this proceeding, except issues related to REC revenues as identified in Paragraph G. The Parties understand that this Stipulation is not binding on the Commission or any Party unless and until it is approved.[17]

36 **2.** The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

37 **3.** The Parties agree this Stipulation represents the entire agreement of the Parties, and it supersedes any and all prior oral or written understandings or agreements related to this docket or this settlement, if any, and no such prior understanding, agreement or representation shall be relied upon by any Party. Parties have negotiated this Stipulation as an integrated document. Accordingly, the Parties recommend that the Commission adopt this Stipulation in its entirety.

38 **4.** The Parties shall cooperate in submitting this Stipulation promptly to the Commission for acceptance, and cooperate in supporting this Stipulation throughout the Commission's consideration of this Stipulation. In particular, each Party shall cooperate in developing a narrative and presenting supporting witnesses, and/or presenting supporting testimony, as described in WAC 480-07-740(2)(a) and (b). The Parties agree to support the Stipulation throughout the Commission's consideration of this Stipulation, and abide by the procedures determined by the Commission for its review of this Stipulation. If necessary, each Party will provide witnesses to sponsor and support this

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[17] The exception is that prior to the Commission's approval of the Stipulation, the Parties agree to support the Stipulation before the Commission. Section III, Paragraph K.4, *infra*.

Stipulation at a Commission hearing. If the Commission decides to hold such a hearing, each Party will recommend that the Commission issue an order adopting the Stipulation. In the event the Commission rejects this Stipulation, the provisions of WAC 480-07-750(2)(a) shall apply. In the event the Commission accepts the Stipulation upon conditions not proposed herein, the provisions of WAC 480-07-750(2)(b) shall apply. In the event the Commission accepts the Stipulation upon conditions not proposed herein, or approves resolution of this proceeding through provisions that are different than recommended in this Stipulation, each Party reserves the right, upon written notice to the Commission and all parties to this proceeding within seven (7) days of the Commission's order, to state its rejection of the conditions. If any Party rejects a proposed new condition, the Parties will: (1) request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of the case pursuant to WAC 480-07-750(2)(a); and (2) cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

39 **5.** In the event the Commission determines that it will reject the Stipulation or accept the Stipulation upon conditions not proposed herein, the Parties request that the Commission issue an order as soon as possible so that the Parties may promptly invoke the provisions of WAC 480-07-750.

40 **6.** The Parties enter into this Stipulation to avoid further expense, inconvenience, uncertainty, and delay. By executing this Stipulation, no Party shall be deemed to have approved, admitted, or consented to the facts, principles, methods, or theories employed in arriving at the terms of this Stipulation, nor shall any Party be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except to the extent expressly set forth in the Stipulation, including but not limited to the agreements set forth in Section III, Paragraphs D-I.

41 **7.** This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document. A Party may authorize another Party to sign on the first Party's behalf. A signed signature page that is faxed or emailed is acceptable as an original signature page signed by that Party.

42 **8.** This Stipulation is the product of negotiation and no part shall be construed against any Party on the basis that it was the drafter.

43 **9.** Each Party agrees to provide all other Parties the right to review in advance of publication any and all announcements or news releases that any other Party intends to make about the Stipulation (with the right of review to include a reasonable opportunity to request changes to the text of such announcements). Each Party also agrees to include in any news release or announcement a statement to the effect that the Commission Staff's recommendation to approve the Stipulation is not binding on the Commission itself.

44 **10.** The effective date of this Stipulation is the date of the Commission order approving it, subject to the procedures of Section III, Paragraph K.4 above.[18]

45 This STIPULATION is entered into by each Party as of the date entered below.

DATED: February 21, 2012.

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[18] The effective date of the provisions wherein the Parties agree to support the Stipulation is the date of the latest dated signature to the Stipulation.

PacifiCorp

By Andrea L. Kelly
Andrea L. Kelly
Vice President, Regulation

Date: 21 February 2012

Staff of the Washington Utilities and Transportation Commission

By ______________________
Gregory Trautman
Assistant Attorney General

Date: ______________________

Public Counsel Section of the Office of the Attorney General

By ______________________
Simon ffitch
Assistant Attorney General

Date: ______________________

Industrial Customers of Northwest Utilities

By ______________________
Melinda Davison
Attorney for ICNU

Date: ______________________

The Energy Project

By ______________________
Brad Purdy
Attorney for The Energy Project

Date: ______________________

PacifiCorp

By ______________________________
Andrea L. Kelly
Vice President, Regulation

Date: ______________________________

Staff of the Washington Utilities and Transportation Commission

By Gregory J. Trautman
Gregory Trautman
Assistant Attorney General

Date: February 21, 2012

Public Counsel Section of the Office of the Attorney General

By ______________________________
Simon ffitch
Assistant Attorney General

Date: ______________________________

Industrial Customers of Northwest Utilities

By ______________________________
Melinda Davison
Attorney for ICNU

Date: ______________________________

The Energy Project

By ______________________________
Brad Purdy
Attorney for The Energy Project

Date: ______________________________

PacifiCorp

By ___________________________
Andrea L. Kelly
Vice President, Regulation

Date: ___________________________

Staff of the Washington Utilities and Transportation Commission

By ___________________________
Gregory Trautman
Assistant Attorney General

Date: ___________________________

Public Counsel Section of the Office of the Attorney General

By ___________________________
Simon ffitch
Assistant Attorney General

Date: 2/21/2012

Industrial Customers of Northwest Utilities

By ___________________________
Melinda Davison
Attorney for ICNU

Date: ___________________________

The Energy Project

By ___________________________
Brad Purdy
Attorney for The Energy Project

Date: ___________________________

PacifiCorp

By ______________________________
Andrea L. Kelly
Vice President, Regulation

Date: ______________________________

Staff of the Washington Utilities and Transportation Commission

By ______________________________
Gregory Trautman
Assistant Attorney General

Date: ______________________________

Public Counsel Section of the Office of the Attorney General

By ______________________________
Simon ffitch
Assistant Attorney General

Date: ______________________________

Industrial Customers of Northwest Utilities

By ______________________________
Melinda Davison
Attorney for ICNU

Date: ______________________________

The Energy Project

By ______________________________
Brad Purdy
Attorney for The Energy Project

Date: ______________________________

PacifiCorp

By ______________________________
Andrea L. Kelly
Vice President, Regulation

Date: ______________________________

Staff of the Washington Utilities and Transportation Commission

By ______________________________
Gregory Trautman
Assistant Attorney General

Date: ______________________________

Public Counsel Section of the Office of the Attorney General

By ______________________________
Simon ffitch
Assistant Attorney General

Date: ______________________________

Industrial Customers of Northwest Utilities

By ______________________________
Melinda Davison
Attorney for ICNU

Date: February 21, 2012

The Energy Project

By ______________________________
Brad Purdy
Attorney for The Energy Project

Date: ______________________________

APPENDIX A

Stipulated Revenue Requirement Adjustments

PacifiCorp
Washington General Rate Case - December 2010 Base Period
UE-111190
Final Settlement Agreement

Filed Price Increase	**12,947,210**
Updates/Corrections Provided Thru Discovery:	
Net Power Cost Updates	(2,932,558)
Ancillary Service Revenue (Seattle City Light) Update	(2,218,496)
Non-Recurring DSM Expense Correction	(68,064)
Subtotal of Updates/Corrections	**(5,219,118)**
Price Increase After Updates/Corrections	**7,728,092**
Settlement Adjustments:	
Legal and Litigation Expense	(16,633)
Automated Meter Reading Savings	(51,633)
Insurance Expense	(384,381)
Advertising Expense	(1,268)
Memberships & Subscriptions Expense	(16,721)
Director's and Officer's (D&O) Insurance	(23,535)
Meals / Legislative / Charitable Expenses	(4,420)
Remove Coal Cost Updates	(1,490,583)
Miscellaneous Rate Base	(114,054)
Production Factor	77,316
Interest True Up	13,842
Miscellaneous Settlement Adjustment	(1,216,021)
Subtotal of Settlement Adjustments	**(3,228,092)**
Total Adjustments From Original Filing	**(8,447,210)**
Stipulated Price Increase	**4,500,000**

APPENDIX B

Results of Rate Spread by Class

TABLE A. PRESENT AND PROPOSED RATES
PACIFIC POWER & LIGHT COMPANY
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS
IN WASHINGTON
12 MONTHS ENDED DECEMBER 2010

Line No.	Description	Curr. Sch. No.	Avg. Cust.	MWH	Present Base Revenues ($000)	Proposed Base Revenues ($000)	Change: Base Increase ($000)	Change: Base %
	(1)	(2)	(3)	(4)	(5)	(6) (5)+(7)	(7)	(8) (7)/(5)
	Residential							
1	Residential Service	16/18	103,965	1,662,889	$137,595	$139,656	$2,061	1.5%
2	**Total Residential**		103,965	1,662,889	$137,595	$139,656	$2,061	1.5%
	Commercial & Industrial							
3	Small General Service	24	18,382	520,891	$43,528	$44,180	$652	1.5%
4	Partial Requirements Service	33	0	0	$0	$0	$0	1.5%
5	Large General Service <1,000 kW	36	1,072	874,471	$61,577	$62,499	$922	1.5%
6	Agricultural Pumping Service	40	5,276	150,522	$11,908	$12,087	$178	1.5%
7	Partial Requirements Service => 1,000 kW	47	1	1,600	$265	$268	$4	1.5%
8	Large General Service => 1,000 kW	48	57	798,535	$45,735	$46,420	$685	1.5%
9	Recreational Field Lighting	54	29	273	$24	$24	$0	0.0%
10	**Total Commercial & Industrial**		24,817	2,346,293	$163,038	$165,478	$2,441	1.5%
	Public Street Lighting							
11	Outdoor Area Lighting Service	15	2,641	3,482	$492	$492	($0)	0.0%
12	Street Lighting Service	51	166	3,429	$675	$675	$0	0.0%
13	Street Lighting Service	52	23	431	$64	$64	$0	0.0%
14	Street Lighting Service	53	198	5,055	349	$349	$0	0.0%
15	Street Lighting Service	57	45	2,117	258	$258	$0	0.0%
16	**Total Public Street Lighting**		3,073	14,514	$1,838	$1,838	($0)	0.0%
17	**Total Sales to Standard Tariff Customers**		131,854	4,023,695	$302,471	$306,972	$4,501	1.5%
18	Total AGA				$722	$722		
19	**Total Sales to Ultimate Consumers**		131,854	4,023,695	$303,193	$307,695	$4,501	1.5%

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 15					
Outdoor Area Lighting Service-Grand Combined					
Mercury Vapor Lamp Charges					
7,000 Lumens	28,540	$10.63	$303,380	$10.63	$303,380
21,000 Lumens	4,661	$20.23	$94,292	$20.23	$94,292
55,000 Lumens	600	$41.86	$25,116	$41.86	$25,116
High Pressure Sodium Vapor Lamp Charges					
5,800 Lumens	1,950	$12.09	$23,576	$12.09	$23,576
22,000 Lumens	1,789	$17.76	$31,773	$17.76	$31,772
50,000 Lumens	463	$28.64	$13,260	$28.64	$13,260
Pole Charges	617	$1.00	$617	$1.00	$617
Total Bills	31,692				
Subtotal	3,496,611		$492,014		492,013
Unbilled	(14,886)		($223)		($223)
Total	3,481,725		$491,791		$491,790
SCHEDULE 16/18					
Residential Service-Combined					
Basic Charge	1,247,577	$6.00	$7,485,462	$6.00	$7,485,462
1st 600 kWh	704,700,398	5.858 ¢	$41,281,349	5.949 ¢	$41,922,626
All addt'l kWh	933,774,927	9.264 ¢	$86,504,910	9.416 ¢	$87,924,247
kW demand	5,366	$1.65	$8,854	$1.65	$8,854
Minimum kW Charge	889	$3.20	$2,845	$3.20	$2,845
kW demand in minimum	88	($1.65)	($145)	($1.65)	($145)
Subtotal	1,638,475,325		$135,283,275		$137,343,889
Unbilled	24,413,208		$2,311,971		$2,311,971
Total	1,662,888,533		$137,595,246		$139,655,860
SCHEDULE 16					
Residential Service					
Includes Schedule 16 Net Metering					
Basic Charge	1,198,727	$6.00	$7,192,362	$6.00	$7,192,362
1st 600 kWh	676,855,975	5.858 ¢	$39,650,223	5.949 ¢	$40,266,162
All addt'l kWh	895,661,508	9.264 ¢	$82,974,082	9.416 ¢	$84,335,488
kW demand	0	$1.65	$0	$1.65	$0
Minimum kW Charge	0	$3.20	$0	$3.20	$0
kW demand in minimum	0	($1.65)	$0	($1.65)	$0
Subtotal	1,572,517,484		$129,816,667		$131,794,012
Unbilled	23,402,927		2,216,085		$2,216,085
Total	1,595,920,410		$ 132,032,752		$134,010,097
SCHEDULE 17					
Residential Service					
Basic Charge	47,507	$6.00	$285,042	$6.00	$285,042
1st 600 kWh	27,072,487	5.858 ¢	$1,585,906	5.949 ¢	$1,610,542
All addt'l kWh	35,859,563	9.264 ¢	$3,322,030	9.416 ¢	$3,376,536
kW demand	0	$1.65	$0	$1.65	$0
Minimum kW Charge	0	$3.20	$0	$3.20	$0
kW demand in minimum	0	($1.65)	$0	($1.65)	$0

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
Subtotal	62,932,050		$5,192,978		$5,272,120
Unbilled	964,791		91,163		$91,163
Total	63,896,841		$ 5,284,141		$5,363,283
SCHEDULE 18					
Residential Service					
Basic Charge	1,073	$6.00	$6,438	$6.00	$6,438
1st 600 kWh	615,959	5.858 ¢	$36,083	5.949 ¢	$36,643
All addt'l kWh	1,893,692	9.264 ¢	$175,432	9.416 ¢	$178,310
kW demand	4,523	$1.65	$7,463	$1.65	$7,463
Minimum kW Charge	731	$3.20	$2,339	$3.20	$2,339
kW demand in minimum	69	($1.65)	($114)	($1.65)	($114)
Subtotal	2,509,651		$227,641		$231,079
Unbilled	37,577		$3,914		$3,914
Total	2,547,229		$231,555		$234,993

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 18X					
Residential Service					
Basic Charge	270	$6.00	$1,620	$6.00	$1,620
1st 600 kWh	155,976	5.858 ¢	$9,137	5.949 ¢	$9,279
All addt'l kWh	360,164	9.264 ¢	$33,366	9.416 ¢	$33,913
kW demand	843	$1.65	$1,391	$1.65	$1,391
Minimum kW Charge	158	$3.20	$506	$3.20	$506
kW demand in minimum	19	($1.65)	($31)	($1.65)	($31)
Subtotal	516,140		$45,989		$46,678
Unbilled	7,913		$809		$809
Total	524,053		$46,798		$47,487
SCHEDULE 24					
Small General Service-Grand Combined					
Seasonal					
Single Phase	1	$103.20	$103	$104.52	$105
Three Phase	100	$153.48	$15,348	$155.76	$15,576
Load Size > 15 kW	3,852	$10.92	$42,064	$11.04	$42,526
Basic Charge					
Single Phase	160,746	$8.60	$1,382,416	$8.71	$1,400,097
Three Phase	61,678	$12.79	$788,862	$12.98	$800,580
Load Size > 15 kW	1,214,867	$0.91	$1,105,529	$0.92	$1,117,678
Total Basic Charges	222,424				
Total Bills	220,586				
All kW >15	779,963	$3.35	$2,612,876	$3.40	$2,651,874
1st 1,000 kWh	130,618,301	9.624 ¢	$12,570,705	9.766 ¢	$12,756,183
Next 8,000 kWh	282,733,257	6.645 ¢	$18,787,625	6.746 ¢	$19,073,184
All additional kWh	114,425,365	5.725 ¢	$6,550,851	5.812 ¢	$6,650,402
Excess Kvar	110,404	56.00 ¢	$61,827	56.00 ¢	$61,827
Discounts		-1.0%		-1.0%	
Single Phase	65	$8.60	($6)	$8.71	($6)
Three Phase	93	$12.79	($12)	$12.98	($12)
Load Size > 15 kW	1,133	$0.91	($10)	$0.92	($10)
All kW	686	$3.35	($23)	$3.40	($23)
1st 1,000 kWh	112,432	9.624 ¢	($108)	9.766 ¢	($110)
Next 8,000 kWh	391,866	6.645 ¢	($260)	6.746 ¢	($264)
All additional kWh	78,100	5.725 ¢	($45)	5.812 ¢	($45)
Excess Kvar	2,501	56.00 ¢	($14)	56.00 ¢	($14)
High Voltage Charge	107	$60.00	$6,420	$60.00	$6,420
Load Size Discount	763	(30.00) ¢	($229)	(30.00) ¢	($229)
Subtotal	527,776,923		$43,923,920		$44,575,739
Unbilled	(6,886,226)		($395,518)		($395,518)
Total	520,890,697		$43,528,402		$44,180,221

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 33					
Partial Requirements Service					
Basic Charge					
<=100 kW	0	$254.00	$0	$259.00	$0
101 - 300 kW	0	$95.00	$0	$96.00	$0
>300 kW	0	$189.00	$0	$192.00	$0
Total Basic Charges	0				
101 - 300 kW	0	$1.67	$0	$1.70	$0
>300 kW	0	$1.37	$0	$1.39	$0
Demand Charges					
All kW	0	$4.37	$0	$4.44	$0
Energy Charges					
1st 40,000 kWh	0	5.217 ¢	$0	5.292 ¢	$0
All additional kWh	0	4.780 ¢	$0	4.850 ¢	$0
Excess Kvar	0	0.0 ¢	$0	56.0 ¢	$0
Excess Kvarh	0	$0.06000	$0	$0.06000	$0
Discounts		-1.0%		-1.0%	
<=100 kW	0	$254.00	$0	$259.00	$0
101 - 300 kW	0	$95.00	$0	$96.00	$0
>300 kW	0	$189.00	$0	$192.00	$0
101 - 300 kW	0	$1.67	$0	$1.70	$0
>300 kW	0	$1.37	$0	$1.39	$0
All kW	0	$4.37	$0	$4.44	$0
1st 40,000 kWh	0	5.217 ¢	$0	$0.00 ¢	$0
All additional kWh	0	4.780 ¢	$0	4.850 ¢	$0
Excess kVar	0	56.0 ¢	$0	56.000 ¢	$0
Excess kVarh	0	$0.06000 ¢	$0	$0.06000 ¢	$0
High Voltage Charge--Primary	0	$60.00	$0	$60.00	$0
Load Size Discount - Primary	0	(30.00) ¢	$0	(30.00) ¢	$0
Standby kW	0	$2.19		$2.22	$0
Overrun kW	0	$17.48		$17.76	$0
Overrun kWh	0	19.120 ¢	$0	19.400 ¢	$0
Subtotal	0		$0		$0
Unbilled	0		$0		$0
Total	0		$0		$0
SCHEDULE 36					
Large General Service < 1,000 kW-Grand Combined					
Basic Charge					
<=100 kW	272	$254.00	$69,088	$259.00	$70,448
101 - 300 kW	9,034	$95.00	$858,230	$96.00	$867,264
>300 kW	3,553	$189.00	$671,517	$192.00	$682,176
Total Basic Charges	12,859				
101 - 300 kW	1,544,723	$1.67	$2,579,688	$1.70	$2,626,029
>300 kW	1,814,587	$1.37	$2,485,984	$1.39	$2,522,276
Demand Charges					
All kW	2,534,702	$4.37	$11,076,648	$4.44	$11,254,076
Minimum kW	4,852	$4.37	$21,204	$4.44	$21,543
Energy Charges					
1st 40,000 kWh	401,736,473	5.217 ¢	$20,958,592	5.292 ¢	$21,259,894

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
All additional kWh	484,775,092	4.780 ¢	$23,172,249	4.850 ¢	$23,511,591
Excess Kvar	567,984	56.00 ¢	$318,071	56.00 ¢	$318,071
Discounts		-1.0%		-1.0%	
<=100 kW	0	$254.00	$0	$259.00	$0
101 - 300 kW	60	$95.00	($57)	$96.00	($58)
>300 kW	133	$189.00	($252)	$192.00	($256)
101 - 300 kW	10,653	$1.67	($178)	$1.70	($181)
>300 kW	86,525	$1.37	($1,185)	$1.39	($1,203)
All kW	73,104	$4.37	($3,195)	$4.44	($3,246)
Minimum kW	200	$4.37	($9)	$4.44	($9)
1st 40,000 kWh	7,060,720	5.217 ¢	($3,684)	5.292 ¢	($3,736)
All additional kWh	18,999,318	4.780 ¢	($9,081)	4.850 ¢	($9,215)
Excess Kvar	19,365	56.00 ¢	($109)	56.00 ¢	($109)
High Voltage Charge	193	$60.00	$11,580	$60.00	$11,580
Load Size Discount	94,637	(30.00) ¢	($28,391)	(30.00) ¢	($28,391)
Subtotal	886,511,565		$62,176,710		$63,098,544
Unbilled	(12,040,078)		($599,402)		($599,402)
Total	874,471,487		$61,577,308		$62,499,142

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 40					
Agricultural Pumping Service-Grand Combined					
Annual Load Size Charge					
Single Phase Bills	1,050	$0.00	$0	$0.00	$0
Three Phase Bills					
< 51 kW	3,812	$0.00	$0	$0.00	$0
< 301 kW	401	$352.00	$141,152	$357.00	$143,157
> 300 kW	13	$1,435.00	$18,655	$1,457.00	$18,941
Total Bills	5,276				
Monthly Bills	36,349				
Customer Count	5,277				
Annual Load Size kW Charge					
Single Phase kW	3,087	$23.44	$72,360	$23.87	$73,687
Three Phase kW					
< 51 kW	52,237	$23.44	$1,224,435	$23.79	$1,242,719
< 301 kW	38,890	$16.32	$634,685	$16.56	$644,018
> 300 kW	5,296	$12.77	$67,630	$12.96	$68,636
Single Phase Minimum Bills	613	$70.32	$43,106	$71.61	$43,897
Three Phase <51kW Minimum Bills	1,038	$140.64	$145,984	$142.74	$148,165
KW in Minimum					
Single Phase kW	38	($23.44)	($890)	($23.87)	($907)
Three Phase <51kW, kW	326	($23.44)	($7,642)	($23.79)	($7,756)
Energy Charges					
All kWh	150,371,403	6.344 ¢	$9,539,562	6.439 ¢	$9,682,415
Excess Kvar	34,428	55.00 ¢	$18,935	56.00 ¢	$19,280
Discounts		-1.0%		-1.0%	
Single Phase	0	$0.00	$0	$0.00	$0
Three Phase					
< 51 kW	0	$0.00	$0	$0.00	$0
< 301 kW	0	$352.00	$0	$357.00	$0
> 300 kW	0	$1,435.00	$0	$1,457.00	$0
Single Phase	0	$23.44	$0	$23.87	$0
Three Phase					
< 51 kW	39	$23.44	($9)	$23.79	($9)
< 301 kW	0	$16.32	$0	$16.56	$0
> 300 kW	0	$12.77	$0	$12.96	$0
Single Phase Min	0	$70.32	$0	$71.61	$0
Three Phase <51kW Min	0	$140.64	$0	$142.74	$0
KW in Minimum					
Single Phase kW	0	($23.44)	$0	($23.87)	$0
Three Phase <51kW, kW	0	($23.44)	$0	($23.79)	$0
Energy Charges					
All kWh	27,827	6.344 ¢	($18)	6.439 ¢	($18)
Excess Kvar	0	55.00 ¢	$0	56.00 ¢	$0
High Voltage Charge	8	$60.00	$480	$60.00	$480
Load Size Discount	39	(30.00) ¢	($12)	(30.00) ¢	($12)
Subtotal	150,371,403		$11,898,413		$12,076,693
Unbilled	151,000		$10,000		$10,000
Total	150,522,403		$11,908,413		$12,086,693

SCHEDULE 47T

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
Large Partial Requirements Service					
Basic Charge					
<=3000 kW	12	$1,365.00	$16,380	$1,386.00	$16,632
>3000 kW	0	$1,650.00	$0	$1,675.00	$0
Total Basic Charges	12				
<=3000 kW variable	23,080	$1.04	$24,003	$1.06	$24,465
>3000 kW variable	0	$0.95	$0	$0.96	$0
All kW	17,245	$7.02	$121,060	$7.12	$122,784
Energy Charges					
All kWh	1,617,598	4.185 ¢	$67,696	4.246 ¢	$68,683
Excess Kvar	0	$0.54	$0	$0.55	$0
Excess Kvarh	0	$0.00060	$0	$0.00060	$0
Standby kW	1,955	$3.510	$6,862	$3.560	$6,960
Overrun kW	1,085	$28.08	$30,467	$28.48	$30,901
Overrun kWh	11,600	16.740 ¢	$1,942	16.984 ¢	$1,970
Subtotal	1,629,198		$268,410		$272,395
Unbilled	(29,155)		($3,909)		($3,909)
Total	1,600,043		$264,501		$268,486

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 48T					
Large General Service 1,000 kW and over-Grand Combined					
Basic Charge					
<=3000 kW	673		$923,230		$937,101
>3000 kW	16		$36,804		$37,100
Total Basic Charges	689				
<=3000 kW variable	1,001,578		$932,059		$949,984
>3000 kW variable	711,179		$171,320		$171,491
All kW	1,501,696		$10,409,980		$10,553,298
Energy Charges					
All kWh	812,352,351		$33,681,218		$34,186,573
Excess Kvar	381,432		$202,258		$206,072
Subtotal	812,352,351		$46,356,869		$47,041,619
Unbilled	(13,817,304)		($621,691)		($621,691)
Total	798,535,047		$45,735,178		$46,419,928
SCHEDULE 48T					
Large General Service 1,000 kW and over-Combined					
Basic Charge					
<=3000 kW	673		$923,230		$937,101
>3000 kW	4		$6,660		$6,764
Total Basic Charges	677				
<=3000 kW variable	1,001,578		$932,059		$949,984
>3000 kW variable	17,090		$11,680		$11,851
All kW	816,580		$5,710,084		$5,791,742
Energy Charges					
All kWh	354,540,351		$14,801,051		$15,017,985
Excess Kvar	205,718		$110,887		$112,944
Subtotal	354,540,351		$22,495,651		$22,828,371
Unbilled	(5,624,507)		($275,477)		($275,477)
Total	348,915,844		$22,220,174		$22,552,894
SCHEDULE 48T					
Large General Service 1,000 kW and over-Secondary Combined					
Basic Charge					
<=3000 kW	542	$1,365.00	$739,830	$1,386.00	$751,212
>3000 kW	2	$1,650.00	$3,300	$1,675.00	$3,350
Total Basic Charges	544				
<=3000 kW variable	790,843	$1.04	$822,477	$1.06	$838,294
>3000 kW variable	8,495	$0.95	$8,070	$0.96	$8,155
All kW	644,985	$7.02	$4,527,795	$7.12	$4,592,293
Energy Charges					
All kWh	288,246,700	4.185 ¢	$12,063,124	4.246 ¢	$12,238,955
Excess Kvar	185,609	$0.54	$100,229	$0.55	$102,085
Subtotal	288,246,700		$18,264,825		$18,534,344
Unbilled	(4,749,669)		($235,903)		($235,903)
Total	283,497,031		$18,028,922		$18,298,441

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 48T					
Large General Service 1,000 kW and over-Primary-Combined					
Basic Charge					
<=3000 kW	131	$1,400.00	$183,400	$1,419.00	$185,889
>3000 kW	2	$1,680.00	$3,360	$1,707.00	$3,414
Total Basic Charges	133				
<=3000 kW variable	210,735	$0.52	$109,582	$0.53	$111,690
>3000 kW variable	8,595	$0.42	$3,610	$0.43	$3,696
All kW	171,595	$6.89	$1,182,290	$6.99	$1,199,449
Energy Charges					
All kWh	66,293,651	4.130 ¢	$2,737,928	4.192 ¢	$2,779,030
Excess Kvar	20,109	$0.53	$10,658	$0.54	$10,859
Subtotal	66,293,651		$4,230,828		$4,294,027
Unbilled	(874,839)		($39,574)		($39,574)
Total	65,418,812		$4,191,254		$4,254,453
SCHEDULE 48T					
Large General Service 1,000 kW and over-Primary Dedicated Facilities					
Basic Charge					
<=30000 kW	0		$0		$0
>30000 kW	12	$2,512.00	$30,144	$2,528.00	$30,336
Total Basic Charges	12				
<=3000 kW variable	0		$0		$0
>30000 kW variable	694,089	$0.23	$159,640	$0.23	$159,640
All kW	685,116	$6.86	$4,699,896	$6.95	$4,761,556
Energy Charges					
All kWh	457,812,000	4.124 ¢	$18,880,167	$4.187 ¢	$19,168,588
Excess Kvar	175,714	$0.52	$91,371	$0.53	$93,128
Subtotal	457,812,000		$23,861,218		$24,213,248
Unbilled	(8,192,796)		($346,214)		($346,214)
Total	449,619,204		$23,515,004		$23,867,034
SCHEDULE 51					
Street Lighting Service Company-Owned					
High Pressure Sodium Vapor					
Per Lamp Charges					
5,800 Lumens	14,671	$8.46	$124,117	$8.46	$124,117
9,500 Lumens	16,370	$10.15	$166,156	$10.15	$166,156
9,500 Lumens-Decorative Series 1	0	$32.24	$0	$32.24	$0
9,500 Lumens-Decorative Series 2	0	$25.07	$0	$25.07	$0
16,000 Lumens	414	$12.97	$5,370	$12.97	$5,370
16,000-Lumens Decorative Series 1	0	$33.40	$0	$33.40	$0
16,000-Lumens Decorative Series 2	0	$26.27	$0	$26.27	$0
22,000 Lumens	18,431	$14.81	$272,963	$14.81	$272,963
27,500 Lumens	959	$18.79	$18,020	$18.79	$18,020
50,000 Lumens	1,980	$24.80	$49,104	$24.80	$49,104
Total Bills	1,992				
Subtotal	3,227,228		$635,730		$635,730
Unbilled	201,387		$39,647		$39,647
Total	3,428,615		$675,377		$675,377

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 52					
Company-Owned Street Lighting Service					
Operation, Maintenance, Depreciation & Fixed Costs			$28,343		$28,343
Dusk to Dawn kWh	405,868	7.814 ¢	$31,715	7.814 ¢	$31,715
Dusk to Midnight kWh	0	8.744 ¢	$0	8.744 ¢	$0
Total Bills	276				
Subtotal	405,868		$60,058		$60,058
Unbilled	25,327		$3,746		$3,746
Total	431,195		$63,805		$63,805
SCHEDULE 53					
Customer-Owned Street Lighting Service - Grand Combined					
Operation, Maintenance, Depreciation & Fixed Costs			$2,386		$2,386
Non-Listed Lumen-Energy Only	2,293,811		$156,736		$156,736
Listed Lumen-Energy Only	2,464,284		$168,961		$168,961
Total Bills	2,376				
Subtotal	4,758,095		$328,083		$328,083
Unbilled	296,917		$20,440		$20,440
Total	5,055,012		$348,523		$348,523

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 53F					
Customer-Owned Street Lighting Service					
Operation, Maintenance, Depreciation & Fixed Costs			$2,386		$2,386
High Pressure Sodium Vapor					
5,800 Lumens-Energy Only	4,503	$2.12	$9,546	$2.12	$9,546
9,500 Lumens-Energy Only	8,288	$3.00	$24,864	$3.00	$24,864
16,000 Lumens-Energy Only	580	$4.36	$2,529	$4.36	$2,529
22,000 Lumens-Energy Only	12,190	$5.81	$70,824	$5.81	$70,824
27,500 Lumens-Energy Only	4,653	$7.86	$36,573	$7.86	$36,573
50,000 Lumens-Energy Only	2,047	$12.03	$24,625	$12.03	$24,625
Metal Halide					
9,000 Lumens-Energy Only	0	$2.67	$0	$2.67	$0
12,000 Lumens-Energy Only	0	$4.65	$0	$4.65	$0
19,500 Lumens-Energy Only	0	$6.43	$0	$6.43	$0
32,000 Lumens-Energy Only	0	$10.18	$0	$10.18	$0
107,800 Lumens-Energy Only	0	$24.19	$0	$24.19	$0
Non-Listed Lumen-Energy Only	1,127,864	6.833 ¢	$77,067	6.833 ¢	$77,067
Listed Lumen-Energy Only-above	2,464,284	¢	$0	0 ¢	$0
Total Bills	1,270				
Subtotal	3,592,148		$248,414		$248,414
Unbilled	224,159		$15,482		$15,482
Total	3,816,307		$263,895		$263,895
SCHEDULE 53M					
Customer-Owned Street Lighting Service					
Operation, Maintenance, Depreciation & Fixed Costs			$0		$0
Option A (Co. O&M) kWh	0	6.833 ¢	$0	6.833 ¢	$0
Option B (Cust. O&M) kWh	1,165,947	6.833 ¢	$79,669	6.833 ¢	$79,669
Total Bills	1,106				
Subtotal	1,165,947		$79,669		$79,669
Unbilled	72,758		$4,958		$4,958
Total	1,238,705		$84,627		$84,627
SCHEDULE 54					
Recreational Field Lighting					
Basic Charge 1 Phase	188	$3.75	$705	$3.75	$705
Basic Charge 3 Phase	156	$6.75	$1,053	$6.75	$1,053
Total Bills	344				
All kWh	276,500	8.111 ¢	$22,427	8.111 ¢	$22,427
Subtotal	276,500		$24,185		$24,185
Unbilled	(3,560)		($229)		($229)
Total	272,940		$23,956		$23,956

PACIFIC POWER
STATE OF WASHINGTON
12 MONTHS ENDED DECEMBER 2010
(Including Effects of Unbilled Revenue, Unbilled MWh and Weather Normalization)

	Units Actual	Present Price	Present Dollars Actual	Proposed Price	Proposed Dollars
SCHEDULE 57					
Mercury Vapor Street Lighting Service					
Overhead System on Wood Poles					
Horizontal Lamp Charges					
7,000 Lumens	11,378	$9.75	$110,936	$9.75	$110,936
21,000 Lumens	1,491	$17.85	$26,614	$17.85	$26,614
55,000 Lumens	0	$36.10	$0	$36.10	$0
Vertical Lamp Charges					
7,000 Lumens	4,848	$9.15	$44,359	$9.15	$44,359
21,000 Lumens	0	$16.65	$0	$16.65	$0
Overhead System on Metal Poles					
Horizontal Lamp Charges					
7,000 Lumens	498	$12.74	$6,345	$12.74	$6,345
21,000 Lumens	464	$21.39	$9,925	$21.39	$9,925
55,000 Lumens	0	$39.67	$0	$39.67	$0
Vertical Lamp Charges					
7,000 Lumens	0	$12.06	$0	$12.06	$0
21,000 Lumens	0	$20.22	$0	$20.22	$0
Underground System					
Horizontal Lamp Charges					
7,000 Lumens	0	$12.73	$0	$12.73	$0
21,000 Lumens	0	$20.70	$0	$20.70	$0
55,000 Lumens	0	$38.99	$0	$38.99	$0
Vertical Lamp Charges					
7,000 Lumens	0	$12.06	$0	$12.06	$0
21,000 Lumens	0	$19.53	$0	$19.53	$0
Post 1977 System					
7,000 Lumens	1,592	$10.19	$16,222	$10.19	$16,222
21,000 Lumens	1,469	$17.84	$26,207	$17.84	$26,207
55,000 Lumens	0	$38.11	$0	$38.11	$0
Contract					
21,000 Lumens	71	$36.57	$2,596	$36.57	$2,596
Total Bills	537				
Subtotal	1,993,008		$243,204		$243,204
Unbilled	124,369		$15,167		$15,167
Total	2,117,377		$258,371		$258,371
Washington TOTALS	4,023,695,075		$302,470,871		$306,972,152
AGA			$722,472		$722,472
Washington TOTALS with AGA	**4,023,695,075**		**$303,193,343**		**$ 307,694,624**

Pacific Power & Light Company
Monthly Billing Comparison
Schedule 16 - Residential Service

	Monthly Billing [1]		Difference	
kWh	Present Schedule 16	Proposed Schedule 16	Total	Percent
50	$9.36	$9.49	$0.13	1.39%
100	$12.17	$12.35	$0.18	1.48%
150	$14.99	$15.20	$0.21	1.40%
200	$17.80	$18.06	$0.26	1.46%
300	$23.42	$23.78	$0.36	1.54%
400	$29.05	$29.49	$0.44	1.51%
500	$34.67	$35.21	$0.54	1.56%
600	$40.29	$40.92	$0.63	1.56%
700	$49.32	$50.10	$0.78	1.58%
800	$58.35	$59.28	$0.93	1.59%
900	$67.38	$68.47	$1.09	1.62%
1,000	$76.41	$77.65	$1.24	1.62%
1,100	$85.44	$86.83	$1.39	1.63%
1,200	$94.47	$96.01	$1.54	1.63%
1,300 *	$103.50	$105.19	$1.69	1.63%
1,400	$112.53	$114.38	$1.85	1.64%
1,500	$121.56	$123.56	$2.00	1.65%
1,600	$130.59	$132.74	$2.15	1.65%
2,000	$166.71	$169.47	$2.76	1.66%
3,000	$257.01	$261.29	$4.28	1.67%

Notes:
* Average Washington Customer
[1] Includes SBC Charge, Low Income Charge, BPA Credit and Deferral Amortization S
[2] Includes $0.09 proposed change in the Low Income Charge

Pacific Power
Washington Low Income
Schedule 91 Surcharge Rates Proposal

Number of customers served		4,720
Increase in average dollar subsidy/ client		10.0%
Administrative Costs ($/cust)	$	65.00

	Admin Costs		Current Program	Proposed Program with 13.637% Increase	Change	Estimated Monthly Surcharge Increase	Customers	Estimated Annual Proposed Revenues
Annual Revenues Collections	current	proposed	$1,470,236	$1,677,542	$207,306			
Administrative Costs ($/cust)	$ 48.00	$ 65.00	$226,560	$306,800	$80,240			
Available for subsidy			$1,243,676	$1,370,742	$127,066			
Schedule 91 Charges Sch.	15		$0.10	$0.11		$0.01	2,641	$3,486
Sch.	16/18(#2)		$0.55	$0.63		$0.08	99,245	$750,292
Sch.	24		$1.14	$1.30		$0.16	18,382	$286,759
Sch.	33		$27.96	$31.77		$3.81	0	$0
Sch.	36		$27.96	$31.77		$3.81	1,072	$408,689
Sch.	40		$11.53	$13.10	(#1)	$1.57	5,276	$69,116
Sch.	47T		$189.21	$215.01		$25.80	1	$2,580
Sch.	48T		$189.21	$215.01		$25.80	57	$147,067
Sch.	51		$1.58	$1.80		$0.22	166	$3,586
Sch.	52		$1.58	$1.80		$0.22	23	$497
Sch.	53		$1.58	$1.80		$0.22	198	$4,277
Sch.	54		$0.55	$0.63		$0.08	29	$222
Sch.	57		$1.58	$1.80		$0.22	45	$972
							127,135	$1,677,542
Number of Qualifying Customers			4,720	4,720	-			$2,698
			first year of two year cycle, no change yet					Rev excess/(short)

(#1) Annual Amount
(#2) reduced by change in new Schedule 17 customers

Cost per Qualifying Customer	current	proposed	Increase /Customer	% Increase /Customer
Average Credit per Customer - (Credit/Customers)	$263.49	$289.84	$26.35	10.00%
Agency Charge per Qualifying Customer	$48.00	$65.00		
Average Cost per Qualifying Customer	$311.49	$354.84		
Annual Revenues - (Average Cost x Customers)	$1,470,233	$1,674,845		
Annual Credits to Customers	$1,368,040	$1,368,045		

Proposed Credit Increase		
Current Credit per Participant plus 10%	110%	$289.84
Additional Proposed Credit - $0 basic charge	based on $6.25/mo.	$0.00
Proposed Credit per Participant		$289.84
total participants	4,720	
Total benefits		$1,368,045
Admin Expense		$306,800
Total Program cost		**$1,674,845**

Pacific Power
Washington Low Income
Energy Rate Credit Proposal

% of Federal Poverty Level (FPL)	Estimated Customers	Total Credit	Discount/ Customer	Proposed Credit ¢/kWh	Estimated kWh
0-75%	2,217	$827,859	$373.41	**5.828**	14,204,850
76-100%	1,411	$362,132	$256.72	**3.921**	9,235,708
101-150%	1,092	$178,058	$163.01	**2.450**	7,267,665
Total Customers	4,720	$1,368,049	$289.84	**4.455**	30,708,222

APPENDIX C

Revised Tariffs

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. INDEX.2
Canceling Original Sheet No. INDEX.2

Tariff Index

NOTE: *No New Service

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 16.1
Canceling Original Sheet No. 16.1

Schedule 16
RESIDENTIAL SERVICE

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
To single-family residential Customers only for all single-phase electric requirements when all service is supplied at one point of delivery. For three-phase residential service see Schedule 18.

MONTHLY BILLING:
The Monthly Billing shall be the sum of the Basic and Energy Charges.
All Monthly Billings shall be adjusted in accordance with Schedules 91, 95, 96, 98, and 191.

Basic Charge: $6.00

Energy Charge:

Base Rate		
5.949¢	per kWh for the first 600 kWh	(I)
9.416¢	per kWh for all additional kWh	(I)

MINIMUM CHARGE:
The monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

CONTINUING SERVICE:
Except as specifically provided otherwise, the rates of this Tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Customer from monthly minimum charges.

RULES AND REGULATIONS:
Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 17.1
Canceling Original Sheet No. 17.1

Schedule 17
**LOW INCOME BILL ASSISTANCE PROGRAM – RESIDENTIAL SERVICE
OPTIONAL FOR QUALIFYING CUSTOMERS**

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
To residential Customers only for all single-phase electric requirements when all service is supplied at one point of delivery. For three-phase residential service see Schedule 18.

MONTHLY BILLING:
The Monthly Billing shall be the sum of the Basic and Energy Charges and the Low Income Energy Credit. All Monthly Billings shall be adjusted in accordance with Schedules 95, 96, 98 and 191.

Basic Charge: $6.00

Energy Charge:

Base Rate		
5.949¢	per kWh for the first 600 kWh	(I)
9.416¢	per kWh for all additional kWh	(I)

LOW INCOME ENERGY CREDIT*:
The credit amount shall be based on the qualification level for which the customer was certified.

0-75% of Federal Poverty Level(FPL):
(5.828¢) per kWh for all kWh greater than 600 kWh (I)
76-100% of Federal Poverty Level(FPL):
(3.921¢) per kWh for all kWh greater than 600 kWh (I)
101-150% of Federal Poverty Level (FPL):
(2.450¢) per kWh for all kWh greater than 600 kWh (I)

***Note: This credit applies to only the energy usage within the Winter months. Winter months are defined as November 1 through April 30.**

MINIMUM CHARGE:
The monthly minimum charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 17.2
Canceling Original Sheet No. 17.2

Schedule 17
**LOW INCOME BILL ASSISTANCE PROGRAM – RESIDENTIAL SERVICE
OPTIONAL FOR QUALIFYING CUSTOMERS**

SPECIAL CONDITIONS:

1. To qualify, a Customer must earn no more than 150% of the Federal Poverty Level. (c)
2. Qualifying Customers will be placed into one of three qualifying levels. A maximum of 4,720 customers will be certified annually. (c)
3. Non-profit agencies will administer the program. They will determine if a customer qualifies for the program and assign them to one of the three income bands. The Company will authorize these agencies to certify customer eligibility for the Program.

CONTINUING SERVICE:

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a Customer from monthly minimum charges.

RULES AND REGULATIONS:

Service under this schedule is subject to the General Rules and Regulations contained in the tariff of which this schedule is a part and to those prescribed by regulatory authorities.

Issued: February 21, 2012 **Effective:** June 1, 2012
Advice No. UE-111190

Issued By Pacific Power & Light Company

By: Andrea Kelly Andrea L. Kelly **Title:** Vice President, Regulation

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 24.1
Canceling Original Sheet No. 24.1

Schedule 24
SMALL GENERAL SERVICE

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
To non-residential Customers whose entire requirements are supplied hereunder with electric service loads which have not exceeded 100 kW more than once in the preceding 12-month period, or with seven months or less of service, whose loads have not registered more than 100 kW. And to seasonal Customers, as defined in Rule 1 of this tariff, with electric service loads which have not exceeded 200 kW more than once in the preceding 12-month period, or with seven months or less of service, whose loads have not registered more than 200 kW. In the case that the motor nameplate horsepower rating is used to determine the seasonal Customer's annual load size, that load size will also be used to determine eligibility for this schedule.

The Company will not switch a Customer between General Service Schedules 24 and 36 more than once in a 12-month period, unless the following exception is met: In the event that a Customer's load increases due to changes in operations, the Company may, at its discretion, place the Customer on a schedule with a higher demand requirement, if so warranted.

Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed.

Emergency, Seasonal, and Remote Service will be furnished by contract in accordance with Rule 2 of this Tariff.

This Schedule is not applicable to standby service.

MONTHLY BILLING:
The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges. All Monthly Billings shall be adjusted in accordance with Schedules 91, 95, 96, 98, and 191.

Basic Charge:

If Load Size* is:	The Monthly Basic Charge* is: Single Phase	Three Phase	
15 kW or less	$8.71	$12.98	(I)
Over 15 kW	$8.71 plus $.92 per kW for each kW in excess of 15 kW.	$12.98 plus $.92 per kW for each kW in excess of 15 kW.	(I)

*Note: kW Load Size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established any time during the 12-month period which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 24.2
Canceling Original Sheet No. 24.2

Schedule 24
SMALL GENERAL SERVICE

MONTHLY BILLING: (Continued)

Seasonal Service Basic Charge: (Optional)

Customers qualifying as Seasonal Service in accordance with Rule 1 of this Tariff, have the option of the Company billing the Basic Charge annually with their November bill.

If Annual Load Size* is:	The Annual Basic Charge is:	
Single-Phase Service, Annual Any size:	\$104.52 plus \$11.04 per kW of Load Size in excess of 15 kW.	(I)
Three-Phase Service, Annual Any size:	\$155.76 plus \$11.04 per kW of Load Size in excess of 15 kW.	(I)

*Note: Annual Load Size is the greater of:
The average of the two greatest non-zero monthly demands established anytime during the 12-month period which includes and ends with the November billing month; or applying the motor nameplate horsepower to the Billing Demand Table from Rule 10(a) of this Tariff.

Demand Charge:

No Charge	for the first 15 kW of demand	
\$3.40	per kW for all kW in excess of 15 kW	(I)

Energy Charge:

Base Rate		
9.766¢	per kWh for the first 1,000 kWh	(I)
6.746¢	per kWh for the next 8,000 kWh	(I)
5.812¢	per kWh for all additional kWh	(I)

MINIMUM CHARGE:
The monthly Minimum Charge shall be the Basic Charge. A higher minimum may be required under contract to cover special conditions.

REACTIVE POWER CHARGE:
The maximum 15-minute reactive demand for the month in kilovolt amperes in excess of 40% of the kilowatt demand for the same month will be billed, in addition to the above charges, at 56¢ per kvar of such excess reactive demand.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 36.1
Canceling Original Sheet No. 36.1

Schedule 36
LARGE GENERAL SERVICE – LESS THAN 1,000 KW

AVAILABLE:

In all territory served by Company in the State of Washington.

APPLICABLE:

To non-residential Customers with electric service loads which have exceeded 100 kW more than once in the preceding 12-month period, but have not exceeded 999 kW more than once in any consecutive 18-month period. And to seasonal Customers, as defined in Rule 1 of this tariff, with electric service loads which have exceeded 200 kW more than once in the preceding 12-month period, but have not exceeded 999 kW more than once in any consecutive 18-month period. In the case that the motor nameplate horsepower rating is used to determine the seasonal Customer's load size, that load size will also be used to determine eligibility for this schedule.

The Company will not switch a Customer between General Service Schedules 24 and 36 more than once in a 12-month period, unless the following exception is met: In the event that a Customer's load increases due to changes in operations, the Company may, at its discretion, place the Consumer on a schedule with a higher demand requirement, if so warranted.

Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed.

This Schedule is not applicable to standby service.

Partial requirements service for loads of less than 1,000 kW will be provided only by application of the provisions of Schedule 33.

MONTHLY BILLING:

The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges; plus applicable Metering and Delivery Adjustments. All Monthly Billings shall be adjusted in accordance with Schedules 91, 95, 96, 98, and 191.

Basic Charge:

If Load Size* is:	The Monthly Basic Charge* is:	
100 kW or less	$259	(I)
101 kW - 300 kW	$ 96 plus $1.70 per kW	(I)
Over 300 kW	$192 plus $1.39 per kW	(I)

*Note: kW Load Size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established any time during the 12-month period which includes and ends with the current billing month. For seasonal Customers, the Load Size will be the greater of this number or the number derived by applying the motor nameplate horsepower to the Billing Demand Table from Rule 10(a) if this tariff.

Demand Charge:

$4.44 per kW for each kW of Billing Demand (I)

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 36.2
Canceling Original Sheet No. 36.2

Schedule 36
LARGE GENERAL SERVICE – LESS THAN 1,000 KW

Energy Charge:

Base Rate		
5.292¢	per kWh for the first 40,000 kWh	(I)
4.850¢	per kWh for all additional kWh	(I)

MINIMUM CHARGE:
The monthly minimum charge shall be the Basic Charge plus the Demand Charge. A higher minimum may be required under contract to cover special conditions.

REACTIVE POWER CHARGE:
The maximum 15-minute reactive demand for the month in kilovolt amperes in excess of 40% of the kilowatt demand for the same month will be billed, in addition to the above charges, at 56¢ per kvar of such excess reactive demand.

PRIMARY VOLTAGE METERING AND DELIVERY ADJUSTMENTS:
The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kV or greater, the above charges will be reduced by 1.0%.

Delivery: For so long as delivery voltage is at Company's available primary distribution voltage of 11 kV or greater, the total of the above charges will be reduced by 30¢ per kW of load size used for the determination of the Basic Charge billed in the month. A High Voltage Charge of $60 per month will be added where such deliveries are metered at the delivery voltage.

The reductions of charges herein shall not operate to reduce the minimum charge.

When a new delivery or an increase in capacity for an existing delivery is, at request of Customer, made by means of Company-owned transformers at a voltage other than a locally standard distribution voltage, the above charges for any month will be increased by 30¢ per kW of load size used for the determination of the Basic Charge billed in the month.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any Customer affected by such change, such Customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company subject to the voltage adjustments above.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 40.1
Canceling Original Sheet No. 40.1

Schedule 40
AGRICULTURAL PUMPING SERVICE

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
To Customers desiring service for irrigation and soil drainage pumping installations only. Service furnished under this Schedule will be metered and billed separately at each point of delivery.

MONTHLY BILLING:
Except for November, the monthly billing shall be the sum of the applicable Energy Charges and the Reactive Power Charge. For November, the billing shall be the sum of the Energy Charge, the Reactive Power Charge, and the Load Size Charge. All Monthly Billings shall be adjusted in accordance with Schedules 91, 95, 96, 98, and 191.

Load Size Charge: (Billed once each year, and to be included in the bill for the November billing period.)

If Load Size* is:	Load Size* Charge is:	
Single-phase service, any size:	23.87 per kW of Load Size but not less than $71.61	(I)
Three-phase service:		
50 kW or less	$23.79 per kW of Load Size but not less than $142.74	(I)
51 to 300 kW	$357 plus $16.56 per kW of Load Size	(I)
Over 300 kW	$1,457 plus $12.96 per kW of Load Size	(I)

*Load Size is the average of the two greatest non-zero Monthly kW, as described on Sheet No. 40.2, established during the 12-month period which includes and ends with the November billing month.

Energy Charge:

Base
Rate
6.439¢ per kWh for all kWh (I)

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 40.2
Canceling Original Sheet No. 40.2

Schedule 40
AGRICULTURAL PUMPING SERVICE

MONTHLY KW:

Monthly kW is the measured kW shown by or computed from the readings of Company's meter, or by appropriate test, for the 15-minute period of Customer's greatest takings during the billing month; provided, however, that for motors 10 hp or less, the Monthly kW may, subject to confirmation by test, be determined from the nameplate hp rating and the following table:

If Motor Size is:	Monthly kW is:
2 HP or less	2 kW
Over 2 through 3 HP	3 kW
Over 3 through 5 HP	5 kW
Over 5 through 7.5 HP	7 kW
Over 7.5 through 10 HP	9 kW

In no case shall the kW of Monthly kW be less than the average kW determined as:

$$\text{Average kW} = \frac{\text{kWh for billing month}}{\text{hours in billing month}}$$

REACTIVE POWER CHARGE:

The maximum 15-minute reactive takings for the billing month in kilovolt-amperes in excess of 40% of the Monthly kW will be billed at 56¢ per kvar of such excess reactive takings. (I)

PRIMARY VOLTAGE METERING AND DELIVERY ADJUSTMENTS:

The above monthly charges are applicable without adjustment for voltage when delivery and metering are at Company's standard secondary voltage.

Metering: For so long as metering voltage is at Company's available primary distribution voltage of 11 kV or greater, the above charges will be reduced by 1.0%.

Delivery: For so long as delivery voltage is at Company's available primary distribution voltage of 11 kV or greater, the total of the above charges will be reduced by 30¢ per kW of load size used for the determination of the Basic Charge billed in the month. A High Voltage Charge of $60 per month will be added where such deliveries are metered at the delivery voltage.

The reductions of charges herein shall not operate to reduce the minimum charge.

When a new delivery or an increase in capacity for an existing delivery is, at request of Customer, made by means of Company-owned transformers at a voltage other than a locally standard distribution voltage, the above charges for any month will be increased by 30¢ per kW of load size used for the determination of the Basic Charge billed in the month.

Company retains the right to change its line voltage or classifications thereof at any time, and after reasonable advance notice to any Customer affected by such change, such Customer then has the option to take service at the new line voltage or to accept service through transformers to be supplied by Company subject to the voltage adjustments above.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 48T.1
Canceling Original Sheet No. 48T.1

Schedule 48T
LARGE GENERAL SERVICE – METERED TIME OF USE 1,000 KW AND OVER

AVAILABLE:
In all territory served by Company in the State of Washington.

APPLICABLE:
This Schedule is applicable to electric service loads which have exceeded 999 kW in more than one month of any consecutive 18-month period. This schedule will remain applicable until Customer fails to exceed 999 kW for a period of 36 consecutive months. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service. Partial requirements service for loads of 1,000 kW and over will be provided only by application of the provisions of Schedule 47T.

MONTHLY BILLING:
The Monthly Billing shall be the sum of the Basic, Demand, Energy, and Reactive Power Charges. All Monthly Billings shall be adjusted in accordance with Schedules 91, 95, 96, 98 and 191.

Basic Charge:	Delivery Service			
If Load Size* is:	Secondary	Primary	Primary Dedicated Facilities >30,000 kW	
Load Size* ≤ 3,000 kW, per month	$1,386.00	$1,419.00		(I)
Load Size* > 3,000 kW, per month	$1,675.00	$1,707.00	$2,528.00	(I)
Load Size Charge*				
≤3,000 kW, per kW Load Size	$1.06	$0.53		(I)
>3,000 kW, per kW Load Size	$0.96	$0.43	$0.23	(I)
Demand Charge:				
On-Peak Period Demand (Monday through Friday: 6:00 a.m. to 10:00 p.m.)				
Per kW for all kW of On-Peak Period Billing Demand	$7.12	$6.99	$6.95	(I)
Energy Charge: Per kWh	4.246¢	4.192¢	4.187¢	(I)
Reactive Power Charge: Per kVar	$0.55	$0.54	$0.53	(I)

*Note: kW Load Size, for the determination of the Basic Charge, shall be the average of the two greatest non-zero monthly demands established any time during the 12-month period which includes and ends with the current billing month.

(continued)

PACIFIC POWER & LIGHT COMPANY

WN U-75

First Revision of Sheet No. 91.1
Canceling Original Sheet No. 91.1

Schedule 91
SURCHARGE TO FUND LOW INCOME BILL ASSISTANCE PROGRAM

All bills calculated in accordance with the schedules listed below shall have applied the following Surcharge.

Schedule 15	$0.11 per month	
Schedule 16	$0.63 per month	(I)
Schedule 18	$0.63 per month	(I)
Schedule 24	$1.30 per month	(I)
Schedule 33	$31.77 per month	(I)
Schedule 36	$31.77 per month	(I)
Schedule 40	$13.10 per year*	(I)
Schedule 47T	$215.01 per month	(I)
Schedule 48T	$215.01 per month	(I)
Schedule 51	$1.80 per month	(I)
Schedule 52	$1.80 per month	(I)
Schedule 53	$1.80 per month	(I)
Schedule 54	$0.63 per month	(I)
Schedule 57	$1.80 per month	(I)

*To be included in the bill for the November billing period.

Issued: February 21, 2012
Advice No. UE-111190
Effective: June 1, 2012

Issued By Pacific Power & Light Company

By: Andrea Kelly Andrea L. Kelly **Title:** Vice President, Regulation

[Service Date March 25, 2011]

BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,	)	DOCKET UE-100749
Complainant,	)	ORDER 06
v.	)	
PACIFICORP D/B/A PACIFIC POWER & LIGHT COMPANY,	)	FINAL ORDER REJECTING TARIFF SHEETS; AUTHORIZING INCREASED RATES; AND REQUIRING COMPLIANCE FILING
Respondent.	)	
. . . .	)	

Synopsis*: The Commission rejects revised tariff sheets PacifiCorp filed on May 4, 2010, but authorizes and requires the Company to file tariff sheets stating rates that will recover approximately $38 million in additional revenue, an increase that the Commission finds to be reasonable. At the same time, the Commission requires the Company to establish a "tracker" mechanism to return to customers through a monthly bill credit revenues the Company receives from the sale of Renewable Energy Credits (RECs). For the first year, the credit mechanism will be sized to return $4.8 million to customers, thereby offsetting, in part, the impact of the rate increase.*

The increase results from a balancing of the statutory factors that rates must be fair, just, reasonable, and sufficient. The Company's increased revenue requirement is being driven by a number of factors, including an increase in net power costs caused by the expiration of certain low-priced natural gas contacts and expiration of Bonneville Power Administration and Mid-Columbia wholesale power contracts; the collection of costs, previously deferred, and return on equity associated with the Chehalis natural gas generation plant approved in the last general rate case, and a substantial amount of investments in transmission and distribution. The Commission is mindful that including these costs in PacifiCorp's rates requires an unusually large increase, particularly in these economic times, but the Commission also recognizes that the Company must be able to recover its prudently incurred costs to be able to provide the service on which its customers depend.

The resulting revenue requirement is based on a capital structure of 49.1 percent equity and 50.6 percent debt, with a 9.8 percent return on equity resulting in an overall rate of return of 7.81 percent. The Commission also makes specific revenue, tax, and rate base adjustments proposed by the parties. The Commission increases, by 21 percent, funding for its Low Income Bill Assistance Program. Finally, the Commission concludes that the rate increase should be spread to all rate schedules, other than street lighting, on an equal percentage basis.

TABLE OF CONTENTS

MEMORANDUM

I. Background and Procedural History

1 **NATURE OF PROCEEDING:** On May 4, 2010, PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company) filed with the Washington Utilities and Transportation Commission (Commission) revisions to its currently effective Tariff WN U-74 with a stated effective date of June 3, 2010. The purpose of the filing was to increase rates and charges for electric service to customers in the state of Washington.

2 PacifiCorp asserted a revenue deficiency of $56.7 million, which would require a rate increase of 20.88 percent for full recovery. The filing, if allowed to go into effect, would have increased PacifiCorp's rates and charges for electric service to customers in the state of Washington by the indicated amount on the stated effective date of the revised tariff pages, June 3, 2010. The Commission suspended operation of the tariffs by Order 01 entered on May 12, 2010, and set this matter for hearing. Under RCW 80.04.130, the suspension date is April 3, 2011.[1]

3 On October 5, 2010, the Commission's regulatory staff (Commission Staff or Staff),[2] the Public Counsel Section of the Office of the Attorney General (Public Counsel),[3] and intervening parties filed their respective responsive testimony. On November 5, 2010, PacifiCorp filed its rebuttal testimony and Staff, Public Counsel, and intervenors filed their respective cross-answering testimony.

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[1] The suspension date is the date on which the revised tariff sheets become effective as a matter of law absent affirmative waiver by the company or entry prior to the suspension date of a Commission final order accepting or rejecting the as-filed tariff pages. If the Commission rejects the as-filed tariff pages, it may leave the company's existing rates unchanged or may order a filing by the company to effect new rates that comply with the Commission's determinations in its final order.

[2] In formal proceedings, such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of the proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[3] Public Counsel and the Industrial Customers of Northwest Utilities are collectively referred to as the "Joint Parties."

4 The Commission provided members of the public an opportunity to submit written comments throughout the proceeding. In addition, the Commission held a public comment hearing in Yakima, Washington, on October 21, 2010. During the public comment hearing, 29 customers presented testimony in opposition to the proposed rate increase. In addition, the Commission received 297 written comments, 291 of which oppose the proposed rate increase.[4]

5 On November 17, 2010, the Commission convened a second prehearing conference to address issues raised by the manner in which the parties filed testimony and exhibits. During an off-record explanatory session, the Commission made available its policy advisors to specifically describe the filing deficiencies and to respond to questions. At the conclusion of the prehearing conference, the Commission required the parties to submit revised and or supplemental testimony and exhibits addressing the deficiencies identified during the second prehearing conference.

6 On November 23, 2010, PacifiCorp filed supplemental and revised testimony. On December 6, 2010, Staff, Public Counsel, and ICNU filed revised and supplemental responsive testimony. On December 10, 2010, PacifiCorp filed revised and supplemental rebuttal testimony and Staff filed supplemental cross-answering testimony.[5]

7 On January 25, 26, and 27, 2011, the Commission conducted evidentiary hearings in Olympia, Washington. Chairman Jeffrey D. Goltz, Commissioner Patrick J. Oshie, and Commissioner Philip B. Jones were assisted at the bench by presiding Administrative Law Judge Patricia Clark. During the course of the hearing, 25 witnesses presented prefiled testimony and exhibits totaling more than 3,200 pages.[6]

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[4] The public comment exhibit, Exh. No. 8, was filed on February 3, 2011, after the evidentiary hearing in this matter had concluded. Accordingly, the Commission admits Exh. No. 8 with this reference. Any party opposing its admission should file an objection within three business days of the date of this Order.

[5] The parties filed numerous corrections and revisions to their testimony which will not be independently referenced in this Order. A complete listing of all revisions and corrections is available in the docket pages of this case.

[6] Bench Request No. 3 was issued, and its response filed, after the hearing concluded in this matter. The Commission will admit the Response to Bench Request No. 3 as Exh. No. 15C absent objection received within three days of the date of this Order.

PacifiCorp presented the testimony of Richard P. Reiten, Dr. Samuel Hadaway, Bruce N. Williams, Gregory N. Duvall, R. Bryce Dalley, Ryan Fuller, Erich D. Wilson, C. Craig Paice, William R. Griffith, Douglas Stuver, and Rebecca Eberle. Staff presented the testimony of Michael Foisy, Thomas Schooley, Kenneth Elgin, Alan Buckley, Kathryn Breda, and Vanda Novak. The Joint Parties sponsored the testimony of Greg Meyer. ICNU presented testimony from Randall Falkenberg, Michael Gorman, Donald Schoenbeck, Michael Early, and Nicholas Nachbar. Walmart offered the testimony of Steve W. Chriss. The Energy Project presented the testimony of Charles Eberdt. The transcript of this proceeding is more than 800 pages.

8 All parties filed initial post-hearing briefs on February 11, 2011. All parties filed reply briefs on February 18, 2011. The Commission resolves the disputed issues and determines the Company's revenue requirement in this Order, as summarized in Appendix A.

9 **APPEARANCES:** Katherine A. McDowell, Amie Jamieson, and Jordan White, McDowell, Rackner & Gibson PC, Portland, Oregon represent PacifiCorp. Melinda J. Davison and Irion Sanger, Davison Van Cleve, P.C., Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Brad M. Purdy, attorney, Boise, Idaho, represents The Energy Project. Arthur A. Butler, Ater Wynne LLP, Seattle, Washington, represents Wal-Mart, Inc., and Sam's West, Inc. (Walmart). Sarah Shifley, Assistant Attorney General, and Simon ffitch, Senior Assistant Attorney General, Seattle, Washington, represent the Public Counsel Section of the Office of the Attorney General (Public Counsel). Donald T. Trotter, Senior Counsel, Olympia, Washington, represents the Commission Staff.

10 **SUMMARY OF COMMISSION DETERMINATIONS:** We find, on the basis of the evidence presented, that PacifiCorp requires rate relief for its electric service operations in the state of Washington, but we also find that the Company's as-filed rates do not meet the statutory fair, just, reasonable and sufficient standard for approval. We conclude that PacifiCorp should be authorized and required to file revised tariff sheets effecting rates on the basis of an increase in revenue requirement of approximately $38 million based on our resolution of the contested issues. The following table summarizes in concise fashion our determinations in this case.[7]

TABLE 1
Summary of Commission Determinations

REVENUE ADJUSTMENTS	**Commission Determination**
Should the Commission establish a tracker mechanism to ensure that ratepayers receive the benefit of Renewable Energy Credits (REC) in rates?	YES
Should the Commission authorize a five-year amortization period for current and past SO_2 emission allowance revenues in its cost of service?	YES
Should the Commission approve PacifiCorp's residential sales temperature normalization adjustment?	YES
Should the Commission approve PacifiCorp's commercial sales temperature normalization adjustment?	NO
Should the Commission approve PacifiCorp's restating and *pro forma* wage increases?	YES
Should the Commission approve PacifiCorp's affiliate management fee of $7.1 million?	YES
Should the Commission approve the Joint Parties' proposed modification to the Company's annual incentive compensation plan?	NO
Should the Commission approve the Joint Parties' proposed modification to legal expenses?	NO
NET POWER COST ADJUSTMENTS	**Commission Determination**
Should the Commission approve an adjustment to include arbitrage sales to reduce net power costs?	YES
Should the Commission approve the parties' partial settlement regarding the Seattle City Light Stateline Contract, wind integration costs, and Chehalis reserves?	YES
Should the Commission approve an intra-hour wind integration adjustment?	YES
Should the Commission approve an adjustment to the Sacramento Municipal Utility District contract?	YES
Should the Commission approve an adjustment related to the Colstrip Unit 4 forced outage rate?	YES
Should the Commission approve an adjustment related to the Direct Current Intertie contract?	YES
Should the Commission approve an adjustment to the Idaho Point-To-Point Transmission Contract?	YES
Should the Commission approve ICNU's logic screen modification?	YES
Should the Commission approve ICNU's eastern market sale adjustments?	NO
Should the Commission approve ICNU's non-firm transmission adjustment?	NO
Should the Commission approve ICNU's modified planned outage schedule for the Hermiston generating plant?	NO
Should the Commission approve ICNU's Jim Bridger Fuel adjustment?	NO
Should the Commission approve ICNU's minimum loading and deration adjustment?	YES

[7] The actual revenue requirement number cannot be stated with specificity until after the Company re-runs its power cost model with the adjustments approved in this Order. However, in Appendix A attached to this Order, we estimate the revenue requirement to be $37,999,194.

TAX ADJUSTMENTS	**Commission Determination**
Should the Commission Staff's modification to the Company's proposed ―repairs deduction" method of accounting?	YES
Should the Commission approve PacifiCorp's current year deferred tax normalization adjustment?	NO
Should the Commission approve the Company's request to establish an interest reserve account?	NO
RATE BASE ADJUSTMENTS	**Commission Determination**
Should the Commission accept Staff's Jim Bridger Mine Operations & Maintenance adjustment?	YES
Should the Commission accept Staff's ―current assets" adjustment?	YES
Should the Commission accept Staff's calculation of working capital?	YES

RATE OF RETURN

Component	**Share (%)**	**Cost (%)**	**Weighted Cost**
Equity	49.1	9.8	4.81
Long-term debt	50.60	5.89	2.98
Short-term debt	0	0	
Preferred	.30	5.41	.02
Overall Rate of Return			**7.81**

	Commission Determination
LOW INCOME PROGRAM	
Should the Commission approve a 21 percent increase in the Schedule 91 surcharge to fund PacifiCorp's Low Income Bill Assistance program	YES
MID-AMERICAN ENERGY HOLDING COMPANY (MEHC) COMMITMENT	
Should the Commission find PacifiCorp has satisfied Commitment 37 made at the time of its acquisition by MEHC?	YES
COST-OF-SERVICE STUDY	
Should the Commission accept PacifiCorp's modifications to its cost-of-service study?	YES
Should the Commission accept ICNU's adjustment to peak demand?	NO
RATE SPREAD	
Should the Commission approve Staff's modification to PacifiCorp's rate spread?	NO
RATE DESIGN	**Commission Determination**
Should the Commission increase the residential basic charge of $6.00 and, if so, to what level?	NO
Should the Commission approve the Company's original rate design?	YES

II. Discussion and Decisions

A. Introduction

11 In the context of a general rate case, our statutory duty is to balance the needs of the public to have safe and reliable electric service at reasonable rates with the financial ability of the utility to prospectively provide such service. The Commission must

establish rates that are ―fair, just, reasonable and sufficient."[8] The rates must be fair to both customers and the utility; just in that the rates are based solely on the record in this case following the principles of due process of law; reasonable in light of the range of potential outcomes presented in the record; and sufficient to meet the financial needs of the utility to cover its expenses and attract capital on reasonable terms.[9]

12 In this case, the parties advocate significantly different revenue requirements for PacifiCorp. We must determine, on the basis of the record, the Company's prudently-incurred expenses and allow recovery of those expenses prospectively in rates. In addition, we must determine what items should be included in the Company's ―rate base" and allow for a reasonable return on that rate base.[10] This process allows the Company to recover its investment in the plant necessary to provide electric service, repay its lenders, and provide it with the opportunity to earn a reasonable return or profit. The sum total of the Company's expenses plus return on rate base is the revenue requirement, or the amount we allow the Company to recover in rates. The Washington Supreme Court explained this ratemaking formula as follows:

> In order to control aggregate revenue and set maximum rates, regulatory commissions such as the WUTC commonly use and apply the following equation:
>
> $$R=O+B(r)$$
>
> In this equation:
> R is the utility's allowed revenue requirement;
> O is its operating expenses;
> B is its rate base; and
> r is the rate of return allowed on rate base.

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[8] RCW 80.28.010(1); 80.28.020.

[9] *Federal Power Commission v. Hope Natural Gas,* 320 U.S. 591 (1944) and *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923).

[10] The rate base includes both the Company's investment in infrastructure plus ―working capital" supplied by investors to fund the Company's daily operations.

> Although regulatory agencies, courts, and text writers may vary these symbols and notations somewhat, this basic equation is the one which has evolved over the past century of public utility regulation in this country and is the one commonly accepted and used.[11]

We use this general formula to calculate PacifiCorp's revenue requirement in this case.

13 We base our analysis on an examination of data from the calendar year that preceded the Company's initial filing, referred to as an "historical test year," because cost, revenue, plant data, and other pertinent information are known and measurable.[12] However, we recognize that actual test year data may not be representative of the Company's operations for the period that rates will be in effect. Thus, subject to important conditions, the Company's rate filing may include restating and *pro forma* adjustments.[13] We further modify the historical test year approach to recognize that, for certain expenses such as the costs the Company incurs to generate electricity, or "net power costs," a forward looking approach is more appropriate. For example, we commence our consideration of the Company's net power costs using its Generation and Regulation Initiative Decision tools model, known as GRID, which forecasts power costs for the rate year. These future costs are then matched to test year loads through the production property adjustment.

14 The parties propose both restating and *pro forma* adjustments. For restating adjustments, we consider whether certain expenses recorded during the test year are extraordinary and should be adjusted to more normal levels for the expenses in question. For *pro forma* adjustments, we consider whether the proposed change is "known and measurable" and, if so, whether it is offset by other factors, a concept

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[11] *Washington Utilities and Transportation Commission v. Puget Sound Energy,* Docket Nos. UE-090704/UG-090705, Order 11 at ¶ 19 (April 2, 2010).

[12] For a more complete discussion of general ratemaking theory in this jurisdiction, *see Washington Utilities and Transportation Commission v. Puget Sound Energy,* Docket Nos. UE090704/UG-090705, Order 11 (April 2, 2010).

[13] WAC 480-07-510(3)(e)(ii) - (iii) provide definitions of restating actual adjustments and *pro forma* adjustments.

known as the —matching principle.” To be –known,” the event that causes a change to test year levels must have occurred either within or soon after, the test year and must be in place during the period rates will likely be in effect. To be —measurable,” the amount of the change must be calculable, not projected or estimated.[14]

15 The –matching principle” requires that all factors affecting a *pro forma* change be considered in determining a *pro forma* level of expense. Offsetting factors may –cancel out” or mitigate the impact of a known and measurable change. There are two aspects to offsetting factors: (1) whether the increase in expense directly produces offsetting benefits; and (2) whether the *pro forma* adjustment is reasonably close to the test year so that offsetting factors can be determined with reasonable accuracy.[15]

16 Once we have determined the total revenues PacifiCorp needs to recover its costs and to have the opportunity to earn its authorized rate of return, we must establish the rates the Company may charge its customers. We use a cost of service study to determine the costs caused by each class of customer, including residential, commercial, and industrial customers. We then determine the rate spread, i.e., the portion of the total authorized revenue that the rates charged to each customer class is responsible for generating. Finally, we establish the rate design, which structures the rates the Company charges each customer class to generate those revenues.

17 We now turn to the issues in this case. PacifiCorp proposed a rather dramatic increase in rates, over 20 percent. While, after receiving responsive testimony by Staff and other parties, the Company reduced its request to 17.85 percent, that is still an exceptionally high request. Understandably, ratepayers who testified at the public comment hearing in this proceeding[16] and who submitted written comments[17]

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[14] Again, there are exceptions for certain projected costs like net power costs.

[15] *All* adjustments proposed by any party should be supported by a written description of each adjustment describing the reason, theory, and calculation of the adjustment. In this proceeding, there were a number of instances of unsupported conclusions and mere arithmetic calculations that posed some difficulties in evaluating the record. This could be explained in part by the fact that since 2006, all requests for rate relief have been resolved by settlement. Though we do not wish to discourage settlements, all parties should understand that the Commission needs to be able to understand fully, and modify where appropriate, the adjustments proposed by the parties.

[16] Transcript, Volume II, pp. 24 – 90.

[17] Exh. No. 8, Public Comments.

expressed outrage at the magnitude of the increase, particularly given the present state of the economy[18] and the fact that this is PacifiCorp's fifth request for a rate increase in six years.[19] Our responsibility is to take these concerns into account in setting rates that are —fair, just, and reasonable." However, part of our statutory mission is also to ensure that rates are —sufficient." Accordingly, though we wish it were not necessary to do so, we do approve a rate increase, and one that by its percentage alone must be deemed substantial. Much of the Company's increased revenue requirement is being driven by an increase in net power costs caused by (1) the expiration of certain low-priced natural gas contracts and expiration of Bonneville Power Administration and Mid-Columbia wholesale power contracts, (2) the collection of costs, previously deferred, and return on equity associated with the Chehalis natural gas generation plant approved in the last general rate case, and (3) a substantial amount of investments in transmission and distribution.[20] Though, as described above, we reject a number of specific costs associated with these items, many of these costs are justified and must be built into rates.[21]

18 We begin our discussion of the disputed issues with the Company's capital structure and cost of capital because those issues have the greatest impact on the revenue requirement in this case. We then discuss the proposed revenue adjustments commencing again with the adjustment with the greatest impact on the revenue requirement, net power costs. Finally, we discuss the remainder of the proposed adjustments as well as the cost-of-service study, rate spread, and rate design.

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[18] Some of the public reaction was succinct and to the point: —2 percent, you must be joking" and —What in the WORLD is going on?" Others testified to some dramatic personal hardships, reciting the realities of job loss, keeping the thermostat at 58 degrees, and no cost-of-living increases for Social Security recipients. *See* Exh. No. 8.

[19] *See* Public Counsel's Post-Hearing Brief at 1; Initial Post-Hearing Brief of Staff at 1. The Commission approved rate increases of 5.3 percent in 2009, 8.5 percent in 2008, and 6.5 percent in 2007. ICNU's Post-Hearing Brief at 2 – 3.

[20] Reiten, Exh. No. RPR-1T at 3 – 4.

[21] Even ratepayers' advocates, ICNU and Public Counsel, as well as our Commission Staff, recognize that many of these costs should be included in revised and increased rates.

B. Capital Structure and Rate of Return

19 The Washington Supreme Court has described the task of the Commission in determining the utility's rate of return:

> [T he rate of return] is the utility's cost of capital, or the amount of money it must spend to obtain the capital it uses to provide regulated products. Rate of return is the weighted average cost of the utility's various sources of capital (the interest it pays on its debt and the rate of return on its equity) that is necessary to permit it to continue to attract the capital required to provide the regulated product or service—in this case, electricity.[22]

20 More specifically, the Commission must determine the appropriate capital structure for the Company for ratemaking purposes and the cost of each capital structure component, including the cost of equity and debt. The selected capital structure when combined with the individual costs of financing establishes the overall return on investment to be applied to the company's rate base.

1. Capital Structure

21 A company's capital structure reflects the way it finances its assets by using equity and debt (and other hybrid securities such as preferred stock). A company's capital structure reflects a blending of equity and debt which ultimately determines a company's exposure to financial risk and the price its ratepayers pay for service. A company may select its own capital structure to meet its needs. However, for ratemaking purposes, the Commission may determine, and frequently has used, a "hypothetical capital structure" on which to set rates.[23] Such a capital structure should be balanced in a way that achieves financial safety while minimizing financial risk so that the company may finance its operations at the least cost.

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[22] *People's Organization for Washington Energy Resources v. The Utilities and Transportation Commission*, 104 Wn. 2d 798, 810 (1986).

[23] *See, e.g., Washington Utilities and Transportation Commission v. Puget Sound Energy,* Docket Nos. UE-090704/UG-090705, Order 11 (April 2, 2010).

22 *Positions of the Parties.* The following table summarizes the parties' positions on this issue:

		PacifiCorp	Staff	ICNU
Overall Rate of Return		8.34%	7.48%	7.66%
Capital Structure	Equity	52.10%	46.50%	49.10%
	Preferred	0.30%	0.30%	0.30%
	Long-term Debt	47.60%	50.20%	50.60%
	Short-term Debt	0.00%	3.00%	0.00%
Cost Rates	Equity	10.60%	9.50%	9.50%
	Preferred	5.41%	5.41%	5.41%
	Long-term Debt	5.89%	5.89%	5.89%
	Short-term Debt	0.00%	3.0%	0.0%

23 PacifiCorp proposes a capital structure of 52.1 percent common equity, 0.3 percent preferred stock, and 47.6 percent long-term debt.[24] This is based on an average of five-quarters, ending December 31, 2010, which the Company argues smoothes volatility caused by expending capital, issuing and retiring debt, and the retention of earnings and infusion of equity.[25] In effect, the Company proposes its actual capital structure.

24 The Company asserts that the equity in its capital structure reflects the significant capital contributions made by MEHC since it acquired the company[26] It argues that a

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[24] Williams, Exh. No. BNW-1T at 3.

[25] *Id.* at 7.

[26] *Id.* at 8, *quoting* a 2006 Commission order, where we acknowledged the ―general trend of increasing equity capitalization in the industry", as further support for the Company's position.

strong equity position is not only consistent with its current Standard & Poor's (S&P) ―A" credit rating, but necessary to maintain its current rating.[27] That ―A"credit rating lowers its capital costs and provides the Company more reliable access to capital markets in both stable and volatile periods.[28] However, the Company points out that it had no plans to access these markets before December 31, 2010, so any capital needs would be met through additional equity infusions from MEHC and the retention of earnings. This indicates continued growth in its equity component.[29]

25 The Company does not recognize short-term debt in its capital structure. It did not expect to have any short-term debt during the period ending December 31, 2010,[30] has none outstanding, and there have been periods of time when it does not use short-term debt. Therefore, it believes, that short-term debt is not a permanent source of financing for the Company. PacifiCorp also argues that the use of short-term debt in the capital structure is inappropriate and inequitable because it would be double-counted as financing both the rate base and Construction Work in Progress (CWIP).[31]

26 The Company's proposed capital structure also includes 0.30 percent preferred stock and 47.60 long-term debt. While it did not intend to issue any new long-term debt for the period ending December 31, 2010, the balance of outstanding debt will decrease as a result of maturities and principal amortization.[32] The resulting debt component

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Washington Utilities and Transportation Commission v. PacifiCorp, Docket UE-050684, Order 04 at 83 (April 17, 2006).

[27] As additional support, the Company asserts that S&P advised that its stand-alone financial metrics are more consistent with a ―BBB" rating.

[28] Williams, Exh. No. BNW-7T at 10.

[29] Williams, Exh. No. BNW-1T at 5. The Company submits that MEHC injected a substantial amount of common equity, in excess of $990 million, on the balance sheet of PacifiCorp. No party disputes this fact.

[30] *Id.* at 3.

[31] *Id.* Construction Work in Progress or ―CWIP" is essentially the amount shown on the utility's balance sheet for capital projects under construction, but not yet complete. Though PacifiCorp does not elaborate on its point, we gather that its argument essentially is that because such CWIP is financed by short-term debt, it is inappropriate also to include such debt in the capital structure.

[32] *Id.*at 8.

would be 47.60 percent of the Company's capital structure. The remainder of the capital structure, 0.30 percent, is preferred stock.

27 In responsive testimony, Staff proposes a hypothetical capital structure of 46.5 percent common equity, 0.3 percent preferred stock, and 3.0 percent short-term debt with a 50.2 percent long-term debt component.[33] It argues a capital structure with 46.5 percent equity would provide a balance of safety and economy and is consistent with the proposition that a company's capital structure should achieve the lowest overall cost of capital.[34] This approach is consistent with Commission decisions that state the general principle that —t[]he appropriate capital structure for ratemaking purposes is one that *balances economy with safety* in view of all of the sources of capital available to the company."[35] Staff contends that PacifiCorp's parent, MEHC, controls the Company's capital structure and has a strong financial incentive to capitalize PacifiCorp with —as much equity as possible."[36] Thus, it implies that the large equity component advocated by PacifiCorp tilts the balance in favor of the Company's shareholders while providing little benefit to its ratepayers.

28 As to the Company's credit metrics, Staff concludes that an equity ratio in the mid-40's would support a —BBB" corporate debt rating and an —A" secured rating.[37] Staff asserts that such credit ratings are reasonable and points out that most electric utilities have a —BBB" rating.

29 In contrast to the Company and ICNU, Staff imputes three percent short-term debt in its hypothetical capital structure arguing that short-term debt is less expensive than equity and such a result would be consistent with the Commission's ruling in the Company's 2005 general rate case.[38] Its estimate is based on examining the

[33] Elgin, Exh. No. KLE-1T at 2.

[34] *Id.* at 11.

[35] *Id.* at 12 – 13, *citing Washington Utilities and Transportation Commission v. PacifiCorp,* Docket No. UE-050684, Order 04, (April 17, 2006).

[36] *Id.* at 13.

[37] *Id.* at 15 – 16.

[38] *Id.* at 19.

Company’s credit facilities and its cost of issuing commercial paper and considering Avista and Puget Sound Energy’s recent cost of short-term debt.[39]

30 The imputed debt represents $500 million which Staff argues is relatively small compared to net plant of $15 billion.[40] Staff also contends that PacifiCorp’s cash flow requires $800 million of external funding which it argues should be derived from cheaper short-term borrowings.[41] It points out the Company retains $1.5 billion in short-term debt credit facilities, from internal sources that could be used to finance its short-term capital needs.[42]

31 In summary, Staff agrees with the Company’s allocation of preferred stock in its capital structure. Accordingly, the remaining component of the capital structure, long-term debt, would represent 50.2 percent.

32 ICNU recommends a hypothetical capital structure of 49.1 percent common equity, 0.3 percent preferred stock, and 50.6 percent long-term debt and represents that its hypothetical capital structure is consistent with the capital structure PacifiCorp proposed in prior proceedings.[43] Starting with the Company's actual common equity ending June 30, 2010, ICNU reduces actual equity by $360 million by removing what it characterizes as the financing associated with: (1) an acquisition adjustment; (2) special deposits (3) short-term investments; and (4) the net amount of affiliated payables and receivable. It asserts that its adjustment reflects the common equity the Company ~~–r~~elied on to invest in utility plant.”[44] ICNU points out that while the Company retained all earnings at the subsidiary level and did not pay dividends to its

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[39] *Id.* at 48.

[40] *Id.*at 20.

[41] *Id.*

[42] *Id.* at 19 -20.

[43] Gorman, Exh. No. MPG-1T at 13,15. ICNU uses an average of PacifiCorp’s most recent five quarters ending June 30, 2010, to determine its proposed capital structure.

[44] *Id.* at 13.

parent, it did not invest all those earnings in utility plant, and equipment for the benefit of the ratepayers.[45]

33 Having agreed with the Company's 0.3 percent preferred stock component, ICNU proposes that the remainder of the capital structure consist of 50.6 percent long-term debt.[46] As to its recommendation's impact on the Company financial ratings, ICNU calculates key metrics used by S&P with its proposed capital structure and return on equity and concludes that each metric will fall within an acceptable range to support the current A utility bond rating and other related ratings.[47]

34 In rebuttal testimony, the Company contends that Staff "seeks to diminish the Company's credit rating without reflecting any of the costs of doing so."[48] In support, it claims that a credit downgrade would result in an increase in debt costs, could increase fees for borrowing arrangements, and could lead to increased collateral requirements.[49]

35 Regarding Staff's imputation of short-term debt, the Company argues that Staff's proposal implies that short-term debt is used as a source of funding for long-term assets in service and to finance CWIP. The Company contends that this would be reasonable if the balance of short-term debt exceeds CWIP because that might indicate it is using short-term debt to finance long-term assets.[50] However, it contends that is not the case and that imputing short-term debt results in "double counting" because CWIP includes the cost of short term debt.[51]

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[45] *Id.* at 12.

[46] *Id.* at 15.

[47] *Id.* at 38 - 41.

[48] Williams, Exh. No. BNW-7T at 11.

[49] *Id.* at 12.

[50] Williams, Exh. No. BNW-7T at 5 - 6.

[51] *Id.* at 7.

36 PacifiCorp also argues that its actual capital structure at the end of the test year includes 0.2 percent of short term debt. However, it argues the Company has no need for short-term debt because it issued a significant amount of new long-term debt in 2009 and received capital contributions from its indirect parent company. [52]

37 Rebutting ICNU's proposed equity allocation, PacifiCorp argues that ICNU mistakenly reduces equity related to resources that are actually located in other jurisdictions. The Company argues that financing is not allocated by jurisdiction and that its capital structure is comprised of operations in all states.[53] It also contends that general financial theory does not support ICNU's proposal to offset common equity by netting it against cash (assets).[54]

38 In response to ICNU's calculation of credit metrics under its proposed capital structure, the Company contends that ICNU failed to properly reflect rating agency adjustments. For example, it points out that ICNU includes less than half of the imputed debt used by S&P.[55] In addition, the Company argues that ICNU ignores the published expectations of the rating agencies, which leads to a false conclusion about the Company's ability to maintain its current ratings.[56]

39 *Commission Decision.* A central tenet of ratemaking is that a Company's capital structure must strike an appropriate balance between safety and economy. In other words, the capital structure must contain sufficient equity to provide financial security, but no more than necessary to keep ratepayer costs at a reasonable level.[57] We conclude that the Company's proposed capital structure contains too much equity, which tips the balance too far in favor of investor interests over ratepayers.

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[52] *Id.* at 4.

[53] *Id.* at 18 - 19.

[54] *Id.* at 19.

[55] *Id.* at 21.

[56] *Id.* at 22.

[57] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1942).

40 In 2006, the Company's equity ratio was 46 percent.[58] Under the control of MEHC, the equity component of the Company's capital structure expanded to the test year level of 52.1 percent, a remarkable level of growth in just three years. This growth is due to MEHC infusing over $990 million of equity into the Company, eliminating the payment of dividends to MEHC, and retiring short-term debt.[59] By the Company's own admission, this financial policy will continue for the near future.[60] PacifiCorp expects additional equity infusions from MEHC and intends to retain earnings rather than paying dividends to MEHC, indicating a trend of future growth in its equity component.[61] While we understand MEHC's interest in expanding PacifiCorp's equity ratio and reaping the benefit of greater equity returns, this interest is inconsistent with the ratepayer interest in a capital structure that reflects economy. Accordingly, as recommended by ICNU, we adopt a hypothetical capital structure for ratemaking purposes consisting of 49.1 percent equity, 0.3 percent preferred stock, and 50.60 percent long-term debt.

41 Regarding the equity component, we believe that Staff's proposed 46.5 percent is too low. We recognize that a substantial part of PacifiCorp's increased equity financing is being used for capital expenditures, such as generation, transmission, and distribution investments that provide value to ratepayers. Therefore, we conclude that it is appropriate to increase the equity component above the 46 percent that the Commission approved in the last litigated rate case in 2006. We also recognize that the decision on the appropriate actual capital structure for PacifiCorp will be made by the parent company, MEHC,[62] and by the ultimate owner, Berkshire Hathaway.

42 We conclude that ICNU provides us with the most reasonable approach for calculating the equity component of the Company's capital structure. ICNU in effect determines its proposed equity ratio by ascertaining the equity used to support plant investment. Therefore, it removed $360 million of equity capital not used to support

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[58] Williams, TR 277.

[59] Gorman, Exh. No. MPG-1T at 12, Williams, Exh. Nos. BNW-1T at 5.

[60] Williams, Exh. No. BNW-1T at 5.

[61] *Id.*

[62] *See* Elgin, Exh. No. KLE-1T at 13.

such plant. This results in an equity component of 49.1 percent and a debt component of 50.60 percent, which we believe strikes an appropriate balance and is likely to maintain the Company's current credit ratings.

43 We are not persuaded, in this case, by Staff's arguments to impute short-term debt in the Company's hypothetical capital structure. As we stated in the 2006 PacifiCorp rate case, "t]he Commission has traditionally included a component for short-term debt, *based on a company's actual capital* structure"[63] Here, we are not persuaded that that the Company's "actual" capital structure contains such short-term debt. This is not to say that, in an appropriate case, we would not impute short-term debt. As Staff notes, it "is a very low-cost source of funds" and PacifiCorp did include such debt in its capital structure in the past.[64] However, our adoption of a 49.1 percent equity ratio already ameliorates the potential adverse effects of the Company's proposed capital structure that we judged to contain an excessive equity component. In summary, we adopt a hypothetical capital structure for ratemaking purposes with 49.1 percent common equity, 0.3 percent preferred stock, and 50.60 percent long-term debt.

2. Cost of Common Equity

44 Determining the cost of capital requires a series of complex decisions but must conform to specific legal criteria. Rates must be "just, fair, reasonable, and sufficient."[65] In the context of this issue, they must be sufficient to meet the financial needs of the company and attract capital on reasonable terms.[66] "Reasonable terms" are those that allow a return "commensurate with returns on investments in other enterprises having commensurate risks."[67]

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[63] *Washington Utilities and Transportation Commission v. PacifiCorp,* Docket UE-050684, Order 04 at 79 (April 17, 2006) (emphasis added).

[64] Elgin, Exh. No. KLE-1T at 19.

[65] RCW 80.80.010(1); RCW 80.28.020.

[66] *Bluefield Water Works & Improvement Company vs. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

[67] *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944).

45 Determining the cost of equity is the most challenging of the various types of financing. Unlike debt, which has a stated cost that is easily determined, the Commission must estimate the cost of equity. There are a number of approaches to estimating the cost of equity.[68] The three approaches used in this case are the Discounted Cash Flow (DCF) method, the risk premium method, and the Capital Asset Pricing Model (CAPM).

46 The DCF model is one of the oldest and widely accepted methods to estimate the cost of equity on a forward-looking basis, and that model is based on two fundamental principles. First, the valuation of an asset by investors is based on the future cash flows that the asset will create, *e.g.,* both the annual dividends and the ultimate capital gains through the sale of a utility stock. Second, the valuation is adjusted by the "time value of money," meaning that a dollar received in the future is worth less than a dollar received today. The discount rate that makes the expected dividends and future sales price of the stock equal to the current market price is the cost of common equity.[69]

47 The Risk Premium Method is based on the proposition that common stocks are riskier than fixed income securities and therefore, require a higher expected return. The basic concept of risk premium can be described by the capital market line, which sets forth the relationship between required return and risk in a graph. The basic components of this methodology are a risk-free rate and a premium for anticipated inflation. Several proxies can be used for determining the risk-free rate and include Treasury bonds, Treasury bills, or corporate bonds. The equity risk premium is constant over time.[70]

48 The Capital Asset Pricing Model (CAPM) method is a method based on modern portfolio theory that describes the relationship between a security's investment risk and its market rate of return. The relationship between these two basic parameters (return and risk) identifies the rate of return that rational investors expect a security to

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[68] Charles F.Phillips, Jr., *The Regulation of Public Utilities,* p. 392- 99, (1995).

[69] David C. Parcell, *The Cost of Capital – A Practitioner's Guide* (1997).

[70] *Id*.

earn, which constitutes a rate that is comparable with the market returns earned by other securities that have comparable risk.[71]

49 *Positions of the Parties.* PacifiCorp proposes a ROE of 10.6 percent and uses the DCF and Risk Premium models. PacifiCorp rejects the use of the CAPM because of the potentially questionable underlying assumptions involved[72] and the conclusion that it would produce “artificially low results,” between 7 percent and 9 percent, under current economic conditions.[73] Therefore, PacifiCorp argues that using the DCF and risk premium analyses provide the most reliable cost of equity estimate.[74] While admitting that the DCF formula does require judgment about future growth rates, PacifiCorp argues that the other component of the DCF formula, dividend yield, is straightforward and “the model's results are generally consistent with actual capital market behavior.”[75]

50 The Company recognizes its inability to directly estimate its cost of equity because it is a subsidiary of MEHC, is not a publicly-traded company, and does not have a transparent market price for its common stock. Hence, one cannot directly apply one of the critical variables of DCF analysis, common stock price. Therefore, PacifiCorp uses a proxy group of 22 companies and employs three variants of the DCF model.

51 The versions are:

- Constant growth using analysts' predictions. This method uses analysts' projections of earnings growth, including *Value Line* and others,[76] and their

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[71] Charles E. Phillips, *The Regulation of Public Utilities*, p. 396 (1995).

[72] Hadaway, Exh. No. SCH-1T at 11.

[73] PacifiCorp's Initial Post-Hearing Brief ¶ 31; Hadaway, TR 251.

[74] Hadaway, Exh. No. SCH-1T at 17.

[75] *Id.*

[76] *Value Line* (valueline.com) is an independent research firm founded in 1931 that serves the professional investment community as a resource of information on estimates and analysis of earnings growth, dividends, and other financial indicators. Likewise, Zacks investment research (zacks.com) is a full-service advisory firm that publishes earnings and dividends estimates, among others, on a regular basis. Finally, Thomson (Thomson.com) is a long-standing

projected long-term nominal Gross Domestic Product (GDP) growth. The result is an estimated GDP growth rate of 5.57 percent.

- Constant growth using historical data. This method is based on up to 60 years of GDP data to project long-term nominal GDP growth. The result is an estimated GDP growth rate of 6.0 percent.
- Multi-stage growth using *Value Line*. This method uses *Value Line's* three-to-five year dividend projections in the first stage in this analysis and the projected long-term nominal GDP growth rate in the second stage.[77]

52 All three versions of the DCF model use *Value Line's* dividend yields computed from *Value Line's* projections of dividends for the coming year. The Company derives stock prices from the three-month average for the months that correspond to the *Value Line* editions from which the underlying financial data are taken.[78] The Company's DCF models produce a cost of equity range of 10.40 percent to 10.90 percent. The Company's proposed 10.6 percent cost of equity is near the middle of this range.

53 PacifiCorp's risk premium analysis uses current and projected single-A bond interest rates as the base and adds an equity risk premium. The Company computes the equity risk premium by first using the average difference between Moody's average public utility bond yields and authorized electric equity returns from 1980-2009 based on actual commission orders. PacifiCorp then adjusts the resulting "basic risk premium" upward for what the Company characterizes as "the strong inverse relationship between equity risk premiums and interest rates" (*e.g.*, when interest rates are high, risk premiums are low and vice versa).[79] The Company's risk premium analysis results in a ROE range from 10.38 percent to 10.60 percent. PacifiCorp's proposed cost of equity lies at the top of this range.

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investment firm that has provided financial analysis and estimates to financial professionals for decades; in 2008 it merged with Reuters PLC and is a publicly-listed company.

[77] Hadaway, Exh. No. SCH-1T at 34 - 35.

[78] Hadaway, Exh. No. SCH-1T at 35.

[79] *Id.* at 39.

54 Staff recommends a cost of equity of 9.50 percent based on its DCF analysis, CAPM analysis, and to a lesser degree, a risk premium analysis. Staff describes the proxy selection process for its DCF analysis as starting with PacifiCorp's 22-company proxy group and eliminating all but six of the companies because of non-utility revenue, excessive risks exposure, or dissimilar markets.[80] Staff argues "a proxy group of twenty-two companies is simply too large and too complex for an investor . . . ."[81] Staff's proxy group excludes all California utilities which it asserts have unreasonably high returns on equity and adds Avista which it asserts is a regional company with similar business characteristics. Therefore, Staff's proxy group consists of seven companies compared to the 22-company proxy group used by the Company and ICNU.[82]

55 Staff primarily relies on its DCF analysis which produces an equity range of 9.00 to 9.75 percent. Staff's DCF analysis produces an average dividend yield of 4.63 percent, roughly 20 basis points less than the Company's estimated average yield of 4.82 percent. Although Staff's dividend yield is not materially different from PacifiCorp's, Staff's dividend growth estimate produces results that are more than 100 basis points lower than those produced in PacifiCorp's DCF model. Staff applies Value Line's dividend growth rate, makes what it characterizes as "more reasonable" adjustments to three of its proxy companies, and concludes that a "reasonable expectation for dividend growth is 4.75 percent."[83]

56 Staff uses the CAPM method as a "check" of its DCF analysis but argues that its results should be used with considerable caution because each element of the CAPM formula is difficult to measure, there is a presumption that the "past is indicative of the future," and the variables of the model are unrelated to the proxy group.[84] Staff's

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[80] Elgin, Exh. No. KLE-1T at 22.

[81] *Id.*

[82] *Id.* Staff also removed some others, including, for example, Black Hills Corporation, which is primarily a gas utility.

[83] *Id.* at 30 – 31.

[84] *Id.* at 40.

CAPM analysis results in a cost of equity range from 8.30 to 9.70 percent with an average of 9.00 percent.[85]

57 Although Staff does not advocate strongly for its risk premium analysis, it calculates a variant of this method as a second —check” of its DCF analysis.[86] Staff describes the risk premium method as the difference between a long-term debt coupon rate and its estimated equity risk premium arguing that the —magnitude of the [risk premium] spread” shows the reasonableness its recommended return on equity. Staff computes PacifiCorp's spread at 453 basis points, which it argues represents —excessive compensation” for equity owners.[87] Staff contends that the 300 to 375 basis point risk premium spread reflected in its recommended DCF return of 9.00 to 9.75 percent is adequate compensation in today's capital markets.[88]

58 Staff concludes that its mid-point recommendation of 9.50 percent based primarily on the DCF analysis, is reasonable and corroborated by its respective calculations using the CAPM and risk premium analyses.[89]

59 ICNU also recommends a 9.50 percent cost of equity. ICNU uses three forms of the DCF analysis: the constant growth model, sustainable growth model, and the multi-stage growth model, along with a risk premium analysis, and the CAPM model.[90] ICNU's recommendation is the mid-point of the 8.9 percent to 10.3 percent range produced by its three analytic approaches.

60 In its DCF analysis, ICNU uses the same proxy group of 22 companies as that of the Company, noting that, compared to the proxy group, PacifiCorp has —comparable total investment risk,” and —comparable or lower financial risk.” Both PacifiCorp and

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[85] *Id.* at 43.

[86] *Id.*at 44.

[87] *Id.* at 45.

[88] *Id.* at 46.

[89] *Id.* at 47.

[90] Gorman, Exh. No. MPG-1T at 16.

the proxy group have an "Excellent" business risk profile, according to Standard & Poor's ranking methodology.[91]

61 ICNU's "analyst growth" approach based on the constant-growth DCF model produces a cost of equity range from 10.45 percent (average) to 10.50 percent (median). Accepting the embedded growth rate of 5.67 percent in its analysis, it contends that this growth rate is not sustainable because it exceeds the overall expected economic growth rate of 5.10 percent over the next five years.[92] However, ICNU cautions that this approach leads to a result that is "inflated" because short-term analyst growth rate projections are not reasonable estimates of long-term sustainable growth.[93]

62 ICNU's sustainable-growth DCF approach produces a lower result than the "analyst growth" method; taking the median, the cost of equity range is from 9.14 percent; and taking the mean, it is 9.92 percent (average). ICNU argues that because the proxy group includes an "outlier" with a return on equity of 19.14 percent, it is more reasonable to use the median result.[94] Without the outlier, the mean return would be 9.48 percent. [95]

63 ICNU argues that its multi-stage DCF approach reflects a non-constant growth curve for a company over time by using three growth periods: short-term, transition, and long-term.[96] This approach produces an average and median return on equity of 9.87 percent and 9.90 percent, respectively. ICNU combines these results with the other DCF approaches to produce a recommended average DCF return of 9.85 percent, with the caveat that it has "strong concerns about the accuracy of the constant growth DCF."[97]

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[91] *Id.* at 17.

[92] *Id.* at 21.

[93] *Id.* at 27.

[94] *Id.* at 24.

[95] *Id.*

[96] *Id.* at 25.

[97] *Id.* at 27.

64 ICNU's risk premium analysis model, based on 30-year bond yields and "A" rated utility bond yields, produces an equity range from 8.98 percent to 9.94 percent with a midpoint of 9.46 percent.[98]

65 ICNU also conducted a CAPM analysis utilizing the basic inputs into such a methodology; market risk-free rate, the Company's beta, and the market risk premium. It uses a projected 30-year Treasury bond yield of 4.7 percent based on long-term forecasts of economists. Much of the debate around the CAPM analysis centers around the appropriate calculation of market risk premiums and ICNU uses long-term estimates of historical real-market return and market risk premium to develop a range of 5.2 percent to 6.7 percent.[99] ICNU's final calculation produces a range of 8.28 percent to 9.31 percent with a midpoint of 8.80 percent.[100]

66 In summary, ICNU recommends a –return on equity range" of 9.10 percent to 9.90 percent. This is based on DCF analysis results of 9.85 percent, a Risk Premium result of 9.46 percent, and a CAPM result of 8.80 percent. The low end is based on the average of its CAPM and risk premium return estimates while the high-end is based on DCF analysis. Therefore, ICNU concludes that a 9.50 percent return on equity is reasonable and would support PacifiCorp's financial integrity.[101]

67 ICNU then conducts various calculations incorporating the above recommendations on capital structure and return on equity on the key financial metrics used by credit rating agencies: debt to Earnings Before Interest Taxes Depreciation and Amortization (EBITDA), funds from operations (FFO) to total debt, and total debt to total capital. It also adjusts for off-balance debt and associated interest expense for

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[98] *Id.* at 32.

[99] *Id.* at 36. This data was taken from Morningstar, *Stocks, Bonds, Bills, and Inflation, 2010 Yearbook.* Morningstar (Morningstar.com) is an independent source of investment advice and analysis that originally was established to provide advice to individuals on mutual funds. It has expanded to provide a full range of independent analysis to institutions and individuals on the risks and returns in equity markets, including historical analysis and forward-looking estimates.

[100] *Id.* at 37.

[101] *Id.* at 37 - 38.

power purchase agreements and operating leases using the S & P report and methodologies. ICNU concludes that its recommendations will produce financial credit metrics that support PacifiCorp's current ―A" secured bond rating.[102]

68 ICNU supports its analysis with a critique of the Company's analysis, arguing that PacifiCorp's nominal GDP growth rates in its DCF analysis are not sustainable in the long run; they are excessive and do not reflect current market expectations.[103] ICNU maintains if the Company had used lower GDP projections (4.9 percent instead of 6 percent), PacifiCorp's return would range from 9.9 percent to 10.1 percent.[104] Lastly, ICNU contends that PacifiCorp's DCF results are overstated because the Company's data is stale and does not reflect the market recovery of the last six to nine months. In summary, its critique of the Company's three DCF analyses results in a downward adjustment from an average of 10.7 percent to 10.0 percent return on equity. [105]

69 Continuing its critique, ICNU argues that the Company's risk premium analysis fails because it inappropriately forced an upward adjustment to its derived average equity risk premium resulting in an inverse relationship between interest rates and equity risk premiums. ICNU contends that the inverse relationship promoted by the Company is inappropriate in today's financial markets and inconsistent with academic literature.[106] Further, ICNU contends that the Company's risk premium analysis unreasonably relied on projected interest rates, the accuracy of which is ―highly problematic."[107] It concludes this risk premium analysis by adjusting the Company's return downward to a mid-point of 9.55 percent from 10.84 percent contending that more reasonable risk premiums produce a range of 9.06 to 10.3 percent.[108]

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[102] *Id.* at 41.

[103] *Id.* at 44.

[104] *Id.* at 42.

[105] *Id.* at 44 and 46.

[106] *Id.* at 48.

[107] *Id.*

[108] *Id.* at 48, 51.

70 In rebuttal, PacifiCorp argues that Staff and ICNU fail to consider financial market turbulence and utility price volatility in their estimates of equity return.[109] It contends that increased market volatility causes investors to require a higher rate of return.[110]

71 PacifiCorp also argues that Staff's and ICNU's use of the CAPM results in flawed cost of equity recommendations because CAPM inputs, using risk-free proxies such as US Treasury rates, are artificially low" due to the Federal Reserve's monetary policies and therefore cannot be relied on."[111] Moreover, it criticizes the inputs used in the risk premium analyses by contending that —t‖o the extent that yields are artificially reduced by the government's expansive monetary policy, risk premium estimates of ROE will be understated."[112]

72 The Company criticizes Staff's selection of its proxy group as subjective and too small to be statistically reliable. PacifiCorp argues that Staff did not use a —carefully selected proxy group" because it merely excludes data and replaces it with its own —subjective inputs."[113]

73 The Company contends that Staff's growth estimates in its DCF analysis are flawed because although Staff starts with *Value Line* growth rates, it then subjectively adjusts its data by eliminating the two highest companies and by substituting reported higher growth numbers with lower estimates.[114] The Company also argues that Staff's earning retention growth method (b-times-r) is simply not proper and not generally used by economists due to its volatile nature. [115] The Company further contends that

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[109] Hadaway, Exh. No. SCH-8T at 2.

[110] *Id.* at 7.

[111] *Id.* at 11.

[112] *Id.*at 11 – 12.

[113] *Id.* at 13.

[114] *Id.* at 15.

[115] *Id.* at 18.

although Staff uses multiple methods to estimate growth for its DCF computation, the use of the data is dominated by subjective adjustments.[116]

74 The Company suggests that ICNU uses negatively-biased model inputs and that ICNU's use of the CAPM produces results that are currently unreliable.[117] PacifiCorp also contests ICNU's use of short-term GDP growth rate forecasts in its DCF analysis arguing that these rates introduce a downward bias to the results and that this approach is not consistent with what it asserts the DCF model requires; including a long-term growth rate.[118]

75 The Company further argues that ICNU's risk premium analysis does not take into consideration that, when interest rates are low, equity-risk premiums increase and vice-versa. The Company adjusts ICNU's computation with its regression analyses approach and argues that when the inverse correlation between interest rates and equity premiums is included, ICNU's risk premium analysis produces a return approximately 78 basis points higher than ICNU's proposal. In summary, the Company argues that its updated computations to ICNU's analysis, not including a CAPM result, will produce an average return on equity of 10.21 percent.[119]

76 *Commission Decision.* Our determination of the cost of equity requires that we set a rate at which the utility earns a return on investment commensurate with the returns of companies with comparable risks. This task is always complex because we must use our informed judgment to estimate how capital markets will respond in the future to a utility's particular needs for debt and equity capital. The complexity of this task is compounded because the period since the Company's last litigated rate case is one marked by the most severe economic recession since the 1930's. This case presents yet another layer of complexity because PacifiCorp is a subsidiary of MEHC and ultimately receives its capital from Berkshire Hathaway. Therefore, we place somewhat greater weight on the selection of the proxy group and its analysis because of the lack of a transparent price for its equity.

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[116] *Id.* at 15.

[117] *Id.* at 23.

[118] *Id.*

[119] *Id.* at 27.

77 Our analysis commences with the composition of a group of companies with business and financial risk comparable to PacifiCorp's. PacifiCorp developed a group of 22 companies for its proxy group. ICNU uses the same group of companies arguing that they are generally comparable in terms of total investment risk, common equity ratio/financial risk, and S&P business risk. Staff creates a new proxy group consisting of six companies from PacifiCorp's proxy group plus Avista, a number that draws significant criticism that it is too small to be statistically reliable.[120] On the other hand, Staff criticizes the Company's larger group as including non-representative utilities.

78 There is merit to both arguments. Clearly the 22 member proxy group proposed by the Company and adopted by ICNU contains some companies of dubious comparability,[121] resulting in flaws with the Company's choice of comparable companies. However, we are more concerned with the size of Staff's proxy group, which at seven companies is of questionable statistical reliability. Narrowing a larger and broader proxy group to a smaller one necessarily requires significant subjective analysis regarding its composition and the criteria by which a given company is included or excluded. In general, the smaller the proxy group, the greater possibility for bias to be introduced due to subjective factors. Staff observes that in the 1980's and earlier, the Commission considered proxy groups in telecommunications rate cases that were as small, or smaller, than the one proposed here. However, there are fundamental structural differences between the telecommunications industry at that time and the energy industry now. There were few large telecommunications companies 30 years ago, and they may have been more comparable to each other than energy companies are today. In any event, we have more confidence in the Company's and ICNU's 22 member proxy group than in Staff's seven member proxy group.

79 Our focus is on the comparable risk underlying proxy group selection. We do not have to winnow down with precision a proxy group to a level of *identical* risk but instead use our best judgment to consider companies with *similar* characteristics and

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[120] *Id.* at 13.

[121] Black Hills Corporation is primarily a gas utility, and DPL, Inc., produces a return on equity of 19.14 percent.

risks.[122] Therefore, we focus our analysis on the DCF methodologies of PacifiCorp and ICNU using their 22-company proxy group.

80 *DCF Analyses:* We first address the several variants of the DCF formulas used in this case and compare their strengths and infirmities. PacifiCorp uses three versions of the DCF formula resulting in a cost of equity range between 10.40 and 10.90 percent.[123] ICNU also uses three variants of the DCF formula and produces a cost of equity range from 9.14 to 10.50 percent.[124] The primary disagreement between PacifiCorp and ICNU is the estimate of the growth element of the DCF formula. We understand the divergent assumptions that lead to these disagreements and recognize that the parties have legitimate differences of opinion. It is especially difficult to select a projected growth rate for the rate year because the parties disagree about how stable the financial markets have become in light of the unprecedented turmoil that began in the fall of 2008.

81 We conclude that ICNU's analysis is the better one for two primary reasons. First, ICNU more accurately describes the impact of the recent turmoil in the financial markets. The Company argues that utility stock prices and performance are significantly worse than in the previous litigated rate case, especially in the last two to three years, which justifies an upward adjustment. ICNU, however, persuasively argues that financial market conditions have recovered significantly in the past six to nine months and that, over a longer period of time, utility stocks have substantially outperformed other indicators stock performance. We agree with ICNU that financial markets have returned to more normal conditions over the past six to nine months if we consider indicators such as credit spreads, access to debt markets, and valuations of utility stock. Though utility stocks have not recovered as much as non-utility stocks during 2009 and the first half of 2010,[125] evidence is clear that utility stocks are

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[122] *See Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S, 679,692 (1923).

[123] Hadaway, Exh. No. SPG-1T at 39.

[124] Gorman, Exh. No. MPG-1T at 19 – 25.

[125] Hadaway, Exh. No. SPG-8T at 6 – 7.

less volatile than non-utility stocks and, in a period of turmoil, are generally considered safer investments.[126]

82 Second, ICNU's criticism of the Company's use of long-term growth rates is valid. Generally speaking, we are hesitant to place too much weight on long-term growth rates, such as nominal GDP rates, because we are uncertain if the growth rates can be sustained over the long-term. It is better to rely on short-term growth rates because we should be able to confirm their reliability in a comparatively brief time. This greater confidence in short-term growth rates leads us to rely more heavily on ICNU's DCF recommendations regarding the various growth estimates.

83 ICNU used its three DCF analyses with the effect of smoothing the impact of their individual results. Because the average considers both long-term and short-term growth rates, the result was an average ROE from the combined DCF methodologies of 9.85 percent.

84 ICNU also adjusted inputs in the Company's GDP growth and Multi-stage growth models, substituting more reasonable growth rates into these models, with the result of revising the Company's range downward from 10.4 to 10.9 percent to 9.9 to 10.1 percent.[127]

85 Summing up the various DCF analyses, the range in the testimony from the low of 9.0 percent (Staff's lower end of its DCF analysis) to 10.9 percent (the Company's upper end) is unrealistic. Adjusting for more reasonable growth rates and giving due consideration to the limits of Staff's small proxy group and the Company's inclusion of some outliers in its proxy group, we find a range of 9.50 to 10.20 a more reasonable range using ICNU's DCF analyses.

86 *Risk Premium Analyses.* PacifiCorp's risk premium analysis produces a range of 10.38 to 10.6 percent based on two methodologies that are somewhat related. The Company first estimates an annual equity risk premium by subtracting the Moody's average bond yield from the authorized returns from state commissions since 1980.

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[126] Gorman, Exh. No. MPG-1T at 6 -8. ICNU's testimony cites the superior performance of the EEI index over the 2000 – 2009 period as 134 percent on a total return basis which substantially outperforms the DJIA return of 14 percent, the S & P 500 index of 9 percent, and the NASDAQ index of negative 44 percent.

[127] *Id.* at 42 – 43.

This yields an equity risk premium of 3.23 percent. However, the Company then adjusts that premium through a regression analysis based on an expectation that, in the future, there will be an inverse relationship between overall interest rates and equity risk premiums. This has the effect of substantially inflating the risk premium to a range of 4.39 to 4.55 percent with a corresponding increase in the return on equity. We are not persuaded that such an adjustment is appropriate, and we are skeptical that such a precise formula based on future estimated projections of inflation can yield such a precise result.

87 ICNU has a more reasonable approach. It develops its risk premium methodology based on two different methods of calculating equity risk premiums. The first attempts to estimate the difference between common equity investments and Treasury bonds while the second calculates the difference between Commission-authorized returns on equity and bond yields for ―A" rated companies like PacifiCorp. ICNU posits two calculations of equity risk premiums under this approach and, after adding them to the comparative rate (either a 30-year Treasury bond or an ―A" rated utility bond) it develops a range of return on equity estimates from 8.98 to 9.94 percent, with a mid-point of 9.46 percent. Staff's analysis is consistent with this approach.[128] Accordingly, we find more reasonable a range of ROE based the Risk Premium method to be between 9.5 and 9.8 percent.

88 *CAPM Analyses.* Finally, we turn to the CAPM analyses performed by Staff and ICNU. The inputs and variables for the CAPM analysis are relatively transparent and easy to perform, although parties usually differ over the calculation of the market risk premium. Both Staff and ICNU derive relatively low results employing the CAPM formula in this case. Staff develops a range of 8.30 to 9.70 percent, with a mid-point of 9.0. ICNU develops a return on equity range of 8.28 to 9.31 percent, with a mid-point of 8.80 percent which it then increased to 9.10 percent to use in its summary calculation of return on equity and ultimate recommendation of 9.50 percent.

89 Each party implies that it uses the CAPM as a ―check" or reference point against which it can compare the variants of the DCF methodologies as well as the risk premium method. In this particular case, there is no dispute that the CAPM methodology produces results that are at the low range of estimates for return on equity. The Company refused to perform a CAPM analysis allegedly because the

[128] Elgin, Exh. No. KLE-1T at 44 - 46.

results are not realistic, citing extremely low interest rates. However, low interest rates are a fact of current financial conditions in capital markets and no party suggests that such conditions can be expected to change in the near future, or at least during the projected rate year for this case.

90 Accordingly, while the CAPM results seem abnormally low those results, at a minimum, reflect a reason to be skeptical about the need for higher ROEs for investors in this stagnant economy. At the least, these CAPM results suggest that we should be receptive to arguments to accept ROEs at the lower end of reasonable ranges developed by the other methodologies.

91 We value each of the methodologies used to calculate the cost of equity and do not find it appropriate to select a single method as being the most accurate or instructive. Financial circumstances are constantly shifting and changing, and we welcome a robust and diverse record of evidence based on a variety of analytics and cost of capital methodologies. As we observed in our most recent litigated case with Puget Sound Energy,

> [T]he Commission has said in more than one order that it appreciates and values a variety of perspectives and analytic results because these serve to better inform the judgment it must exercise than would a single model, or a single expert's opinion. We reiterate that perspective here. We value and rely on multiple methodologies, models, and expert opinions to develop a robust record of evidence to inform our judgment. *It is particularly important to take multiple methods and models into account in the present circumstances of financial turmoil that may affect the input values used in each method*.[129]

Consistent with that statement, we expect the parties to submit evidence and recommendations utilizing all widely-accepted methodologies.[130]

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[129] *Washington Utilities and Transportation Commission v. Puget Sound Energy,* Docket UE-090704/UG-090705, Order 11 (April 2, 2010).

[130] In this case, the Company chose not to present a CAPM analysis because it stated that the results would be ―artificially low" or it would not pass the ―smell test." By not submitting an analysis, we were denied a tool by which to evaluate the CAPM analyses submitted by other parties. Though those parties submitted their CAPM analyses as a ―check" on the other methodologies, as discussed above, they were a useful check that merited more of a review than was provided by the Company.

92 *Case Comparison.* PacifiCorp cites other recent Commission cases, and the positions taken by Staff witnesses in those cases, as evidence that the Staff recommendation is too low.[131] The Company is correct that in Puget Sound Energy's most recently litigated general rate case decided a year ago, we set that company's ROE at 10.1 percent.[132] More recently, we approved a settlement in Avista's most recent rate case that set the ROE at 10.2 percent in November 2010, although we did not have a chance to separately consider the ROE.[133] However, the most recently litigated determination setting the PacifiCorp's cost of capital, albeit in Idaho, lowered the Company's ROE to 9.9 percent in that jurisdiction.[134] Though by no means binding on us, other state commission decisions have set ROEs well below 10.0 percent. [135] Given the relatively low interest rates in the current economic climate, it is fair to assume a general downward trend of ROEs, and certainly a cost of equity lower than the 10.6 percent proposed by PacifiCorp.

93 The return on equity for PacifiCorp, therefore, must be within the reasonableness ranges established in the record. As we have stated, we place substantial weight on ICNU's DCF analysis and its critique of the Company's DCF analysis. We also agree with ICNU's and Staff's criticism of the Company's risk premium analysis. The range of DCF-derived ROEs is 9.55 to 10.21 percent. The range of Risk Premium-derived ROEs is 9.4 to 9.8 percent. The analysis for CAPM gives further weight to a lower adjustment. The highest common ROE in both ranges is 9.8 percent.

94 Based on our review of the extensive record in this case and on our reasoning above, we exercise our informed judgment and conclude that PacifiCorp's cost of equity in

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[131] PacifiCorp Initial Post-Hearing Brief at 9 – 10; *see* Elgin, TR 697 - 701.

[132] *Washington Utilities & Transportation Commission v. Puget Sound Energy,* Dockets UE 090704/UG-090705, Order 11 (April 2, 2010).

[133] *Washington Utilities & Transportation Commission v. Avista Corp*., Docket UE-100467, Order 07 (November 19, 2010). This cost of equity was the result of a settlement, so we give this case the least weight in our consideration.

[134] Reiten, Exh. No. RPR-11; *In re PacifiCorp,* 2011 WL 770798 (Idaho P.U.C.) (February 8, 2011). In that proceeding, the Company, as here, requested a 10.6 percent ROE.

[135] *See, e.g., Re Niagra Mohawk Power Corporation,* 286 P.U.R. 4th 401, 2011 WL 286478 (N.Y.P.S.C., Jan. 24, 2011) (setting ROE at 9.3 percent if the company does not file an increase in rates for one year; otherwise, the ROE would be set at 9.1 percent).

this case should be set at 9.80 percent. We believe that such a conclusion is supported by the evidence and a comparative weighting of all the methodologies submitted.

3. Cost of Preferred Stock

95 *Positions of the Parties.* The Company computes its embedded cost of preferred stock by dividing the annual dividend rate by the per-share net proceeds for each series. The embedded cost is multiplied by total par or stated value of each series. Total annualized cost is divided by the total amount of preferred stock outstanding resulting in the weighted average cost or the embedded cost of the company's preferred stock.[136] PacifiCorp uses a December 31, 2010, *pro forma* cost of 5.41 percent.[137] Neither Staff nor ICNU contest PacifiCorp's cost of preferred stock.[138]

96 *Commission Decision.* We accept PacifiCorp's undisputed cost of preferred stock to calculate PacifiCorp's overall rate of return.

4. Cost of Long-Term Debt

97 *Positions of the Parties.* The Company computes its embedded cost of long-term debt by calculating the cost by issue based on each series' interest rate and net proceeds at issuance date resulting in bond-yield-to-maturity for each series of debt. For variable rate securities, the Company uses costs at December 31, 2009.[139] Bond yields were then multiplied by the outstanding principal amount resulting in the annualized cost for each issue. The total annual costs divided by total principal outstanding produces the weighted average cost for all long-term debt issues.[140] The Company's embedded cost of long-term debt, as of December 31, 2010, was computed at 5.89 percent.[141] The Company asserts that its cost of long-term debt is reasonable and compares

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[136] Williams, Exh. No. BNW-1T at 15.

[137] *Id.* at 16.

[138] Elgin, Exh. No. KLE-1T at 3, 7; Gorman, Exh. No. MPG-3 at 1.

[139] Williams, Exh. No. BNW-1T at 14.

[140] *Id.* at 15.

[141] *Id.*

favorably with other utilities under the Commission's jurisdiction.[142] In response to Staff's and ICNU's testimony on capital structure and cost of capital, the Company contends that its cost of debt would increase substantially if its credit rating were to decrease to a —BB."

98 Staff and ICNU do not contest PacifiCorp's calculation of the cost of long-term debt.[143]

99 *Commission Decision.* We adopt the undisputed cost of long-term debt as 5.89 percent.

100 The following table is a summary of our decisions on an appropriate capital structure for the Company and the cost for each component:

Commission Decision

	Share %	Cost %	Weighted Cost %
Equity	49.10	9.80	4.81
Long-term Debt	50.60	5.89	2.98
Short-term Debt	0.00	0.00	0.00
Preferred	0.30	5.41	0.02
OVERALL ROR			7.81

5. General Commitment 37

101 By Order 07 entered February 22, 2006, in Docket UE-051090,[144] the Commission accepted the Company's commitment for five years, following the acquisition of

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[142] PacifiCorp's Initial Post-Hearing Brief at 9 -10.

[143] Elgin, Exh. No. KLE-1T at 47; Gorman, Exh. No. MPG-3 at 1.

[144] *In the Matter of the Joint Application of MidAmerican Energy Holdings Company and PacifiCorp d/b/a Pacific Power & Light Company For an Order Authorizing Proposed Transaction.*

PacifiCorp by MEHC, to spread incremental long-term debt issuances 10 basis points below the Company's similarly-rated peers.[145] The Company states that the five-year commitment ended on March 21, 2011 (before the end of the suspension period in this docket).[146] The Company requests that the Commission recognize its compliance with General Commitment 37 and include a finding in the final order in this case that the requirements of the Commitment been fulfilled and the Commitment is complete.[147]

102 *Commission Decision.* No party opposed PacifiCorp's request. We find that PacifiCorp fulfilled the requirements of Commitment 37 and this Commitment is complete.

C. Revenue Adjustments

1. Net Power Costs

a. Introduction.

103 Net power costs (NPC) represent the costs the Company incurs to generate and transmit electricity to its customers. Many of the issues in the determination of NPC involve evaluation of the merits of the Company's Generation and Regulation Initiatives Decision tools model, known as ―GRID."[148] The Company describes in general terms how the model works:

> The [GRID] model is the Company's hourly production dispatch model, which is used to calculate net power costs. It is a server-based application that uses the following high-level technical architecture to calculate net power costs:

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[145] Williams, Exh. No. BNW-1T at 16. Order 08 was subsequently entered March 10, 2006, in Docket UE-051090, adding commitments based on the Commission's adoption of the ―most favored state clause." These additional commitments did not affect Commitment 37.

[146] *Id.* The suspension period in this case ends April 3, 2011.

[147] *Id.* at 17.

[148] Duvall, Exh. No. GND-1T at 8. The general operations of the GRID model are also described in Duvall, Exh. No. GND-2.

- An Oracle-based data repository for storage of all inputs
- A Java-based software engine for algorithm and optimization processing
- Outputs that are exported in Excel readable format
- A web browser-based user interface[149]

104 Expert witnesses from Staff and ICNU devote considerable portions of their testimony on net power costs to criticisms of the GRID model's limitations and PacifiCorp's choice of inputs and settings used in it.[150] Much of the debate on the contested adjustments analyzed below involves the question of whether the GRID model adequately estimates power costs and whether the GRID model performs well enough to determine certain costs either ―inside GRID" or ―outside GRID."[151]

105 In assessing the differing views of the experts, we are mindful of the fact that the GRID model and its data bases are designed, built, and supplied by PacifiCorp. Accordingly, in addition to the general burden of proof the Company bears to demonstrate that its overall rates are appropriate, the Company has the obligation to demonstrate that the *Company's* costs are appropriately captured in the *Company's* model. If a given cost is challenged by another party, PacifiCorp cannot satisfy its burden of proof by responding only to the effect that ―the GRID model captures the costs correctly."

b. Arbitrage Sales Margin

106 There are two types of short-term transactions or ―arbitrage sales" at issue in this case. The first, called locational arbitrage, is the buying of power at one location and the simultaneous selling of power at another location. The second type of transaction is an energy trading opportunity that occurs when the Company has already entered into what may be a longer term position on energy or sales but then executes short-term purchases or sales to optimize revenue in response to daily or weekly prices.[152]

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[149] Duvall, Exh. No. GND-2 at 1 - 16.

[150] *See, e.g.*, Buckley, APB-1CT at 5 - 9; Falkenberg, RJF-1T at 56.

[151] *See, e.g.,* Buckley APB-1CT at 6, 12; Falkenberg, RJF-1CT at 9, 28.

[152] Buckley, Exh. No. APB-1CT at 5 - 6.

107 *Positions of the Parties.* The Company contends that its GRID model accurately determines resource dispatch including “balancing market purchases and sales necessary to balance and optimize the system and net power costs taking into account the constraints of the Company’s system in the west control area.”[153]

108 Staff claims the model does not include any revenue from arbitrage sales. To reflect these transactions, Staff proposes an “arbitrage sales adjustment” that increases operating revenues from power sales by $527,315, thereby reducing NPC expenses.[154] Staff calculates its adjustment as 90 percent of the four-year average of the transactions to arrive at its $527,315 adjustment. It argues that a 10 percent “profit-sharing” with PacifiCorp maintains the Company’s incentive to maximize the use of its transmission system.[155]

109 ICNU makes a comparable “added sales margins” adjustment that increases operating revenues from power sales and reduces NPC by $585,874.[156] ICNU explains that its adjustment is larger because it does not include Staff’s 10 percent “profit sharing” deduction in its calculation.[157]

110 In rebuttal testimony, the Company opposes both adjustments arguing that the GRID’s system of balancing sales and purchases act as a proxy for future short-term firm sales and purchases, including arbitrage transactions.[158]

111 *Commission Decision.* Staff and ICNU’s proposed adjustments raise the essential question of all power cost modeling: how well does the model capture expected expense and revenues of actual utility operations? The Company acknowledges that

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[153] Duvall. Exh. No. GND-2 at 1 - 2.

[154] Buckley, Exh. No. APB-1CT at 9.

[155] *Id.* at 8.

[156] Falkenberg, Exh. No. RJF-1CT at 2.

[157] *Id.*

[158] Duvall, Exh. No. GND-5T at 31 - 32.

arbitrage sales occur and argues that the system balancing in the GRID model acts as a proxy for these sales. The question is whether the GRID model represents short-term sales. In this case, we are convinced that it does not.

112 We should accept proxy results only if no better alternative is available. In this case, we have a better alternative: the four-year average of actual operations. PacifiCorp does not argue that Staff's and ICNU's numbers are not representative of the sales it would anticipate during the term rates will be in effect. Accordingly, we accept ICNU's calculation of arbitrage sales.

113 The next issue is whether all arbitrage sales revenues should be used to offset net power costs, as proposed by ICNU, or whether a portion of those revenues should be "shared" with the Company, as proposed by Staff. As a general rule, we do not believe it necessary to provide monetary incentives to utilities for properly managing assets under their control. Having found the expected revenue to be reasonable given the Company's history of actual sales, we believe the Company has sufficient reason to continue to prudently manage its sales opportunities. Should it do otherwise, the Company would risk incurring a loss from this adjustment because it has the effect of reducing NPC. For this reason, we do not accept Staff's "profit sharing" proposal, and we increase operating revenues by $585,874.

c. Seattle City Light (SCL) Stateline Contact

114 PacifiCorp entered into contracts with Seattle City Light (SCL) to receive real time output from SCL's share of the Stateline wind farm. The Company returns power two months later. The SCL Stateline contract terminates during the rate year on December 31, 2011.[159]

115 *Commission Decision.* During the hearing, the parties reached agreement on how to address the SCL Stateline Contract in this case.[160] The parties concur that the contract should be treated in the manner presented in Company's rebuttal testimony and agree to reduce NPC expense by $349,229. We accept the parties' agreement on this issue

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[159] Buckley, Exh. No. APB-1CT at 9.

[160] Exh. No. 15C, Response to Bench Request No. 3.

with the understanding that this agreement, like all settlement agreements, may not be used as a precedent in future proceedings.

d. Wind Inter-hour Integration Costs

116 Wind integration costs refer to the costs the Company incurs to manage wind-generated power in conjunction with its other power sources. The Company includes two categories of wind integration charges: one for the Company's wind resource located in the Bonneville Power Administration's (BPA) control area and another one for the wind resources located in the Company's West Control Area.[161] Staff and ICNU proposed adjustments to the Company's inter-hour wind integration charges,[162] and in its rebuttal testimony, the Company accepted all Staff and ICNU's inter-hour adjustments except for those that relate to the SCL Stateline exchange contract, reducing operating expense by $220,983.

117 *Commission Decision.* The Company's acceptance of all inter-hour wind integration adjustments, save the one associated with the SCL Stateline contract, removes the majority of these costs from dispute. The inter-hour wind integration costs associated with the SCL Stateline Contract were resolved according to the terms expressed in Section II.C.1.c above.[163] We accept the parties' agreement on this issue, again with the understanding that this agreement may not be used as a precedent in future proceedings.

e. Wind Intra-Hour Integration Cost

118 *Positions of the Parties.* The Company also includes intra-hour wind integration costs in its NPC calculation. However, rather than determining these costs through its GRID model, PacifiCorp uses separate wind integration studies based on the Company's 2008 Integrated Resource Plan.[164] Since the last rate case, the Company

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[161] Duvall, Exh. No. GND-1T at 15 - 16.

[162] Buckley, Exh. No. APB-1CT at 22 -23; Falkenberg, Exh. No. RJF-1CT at 35. This opposition is discussed in detail in the subsequent subsection d entitled ―Wind Intra-hour Integration Costs." As a result of the parties' settlement on wind inter-hour integration costs, discussed below, these arguments are essentially moot and will not be repeated in the subsection.

[163] Exh. No. 15C, Response to Bench Request No. 3.

[164] Duvall, Exh. No. GND-1T at 6.

asserts its costs for wind integration increased from $1.15 per megawatt hour (MWh) to $6.97 per MWh.[165]

119 Staff states that the Commission should remove all wind integration costs because the Company's wind integration costs fail to pass the known and measurable standard and the facilities do not provide power to PacifiCorp.[166] Based on its review of four non-Company owned facilities,[167] Staff recommends removing all intra-hour wind integration costs for these facilities from NPC.

120 Staff questions the reliability of the Company's data showing the cost increase since the last rate case.[168] The study updating these costs, though anticipated in August 2010, was not completed until September 2010. Should these costs be updated now, the Company claims that they would be even higher, $9.01 MWh.[169] Staff states that it has not had the opportunity to review or analyze the updated study because it was filed late and shortly before Staff's testimony was due in this case. Because of its complexity and numerous revisions, Staff concludes that the study does not produce integration costs that meet the Commission's known and measurable standard. Staff proposes removal of wind integration costs for plants from which Washington ratepayers receive no power and which, it alleges, are not known and measurable.

121 ICNU also supports removing PacifiCorp's intra-hour wind integration costs for non-SCL wind farm costs, Oregon QFs, Campbell wind farm, as well as for the SCL Stateline contract the parties reached a compromise on. ICNU opposes non-SCL wind farm costs and Campbell wind farm costs because the Company's Open Access Transmission Tariff (OATT) doesn't have a provision for charging the wind customer

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165 *Id.*

166 Buckley, Exh. No. APB-1CT at 22 – 23.

167 These projects are the SCL Stateline Wind Farm, the non-SCL owned Stateline project, the Campbell Wind Farm, and the Oregon Qualifying Facilities. *See* Buckley, Exh. No. APB-6 at 1.

168 Buckley, Exh. No. APB-1CT at 22.

169 *Id.*

for wind integration services.[170] ICNU also states that generation and costs for QFs are under the WCA and are assigned to each WCA state.

122 In a separate adjustment, ICNU supports removing PacifiCorp's intra-hour wind integration costs for Company-owned wind projects,[171] and argues that these costs were determined outside the GRID model.[172] ICNU also contends, for a number of reasons, that the costs are inaccurate and high.[173] It proposes its adjustment based on a wind cost derived from ICNU's use of the GRID to determine intra-hour wind integration costs for Company-owned wind resources.[174]

123 In rebuttal testimony, the Company proposes a compromise approach that, for this case, would use ICNU's GRID-based intra-hour integration cost projections for Company-owned resources costs. Rather than push for a decision in this docket, it would defer Commission approval of the proper modeling of wind integration in GRID to a future proceeding in which all parties have the opportunity to thoroughly evaluate intra-hour wind integration modeling proposals.[175]

124 In its testimony and its brief, PacifiCorp also argues that it incurs these wind integration costs pursuant to the Federal Energy Regulatory Commission's (FERC) OATT.[176] Because FERC has exclusive authority over these costs pursuant to the Federal Power Act, states may not conclude that these rates are unreasonable and must pass them through to the retail customers.[177] Staff and ICNU respond that this is not an instance in which the Commission is failing to pass through a federally

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[170] Falkenberg, Exh. No. RJF-1CT at 45 – 46.

[171] *Id.* at 42 - 44.

[172] *Id.* at 35.

[173] *Id.* at 36 - 37 (listing eleven reasons).

[174] Falkenberg, Exh. No. RJF-1CT at 42 - 44.

[175] Duvall, Exh. No. GND-5T at 28.

[176] Duvall, Exh. No. GND-5T at 44 – 47, PacifiCorp Initial Post-Hearing Brief ¶¶ 51 – 52.

[177] PacifiCorp Initial Post-Hearing Brief ¶¶ 81 – 82.

approved rate. Rather, these are interstate costs and belong in the federal jurisdiction.[178]

125 *Commission Decision.* We accept Staff and ICNU's proposal to remove the intra-hour wind integration costs for non-owned facilities. All costs for which a utility seeks recovery must be known and measurable. In this case, the Company calculated these intra-hour wind integration costs outside its own power supply model and presented an updated study that did not afford Staff and ICNU a reasonable opportunity for review. The wind integration costs at issue represent a six-fold increase in one year, and if updated, would reflect an even greater increase. Thus, the Company bears the burden to demonstrate that the substantial increase is warranted. We conclude that PacifiCorp failed to satisfy its burden to demonstrate that these costs are known and measurable.

126 Nor can PacifiCorp evade its evidentiary burden by claiming that the costs are associated with a FERC tariff. A utility cannot use a federal tariff to justify its failure to quantify the costs for which it seeks recovery in a state proceeding. We agree with Staff and ICNU that the Supremacy Clause of the United States Constitution does not require the Commission to pass through these costs. FERC has not set a wholesale wind integration rate under the Company's OATT, and accordingly, PacifiCorp's remedy is to file with FERC for an amendment to its OATT. Indeed, PacifiCorp indicated that it planned to do just that.[179] These costs should be borne by the third-parties who create these costs, not by Washington ratepayers who do not receive the power generated at these facilities. Rejecting these intra-hour wind integration costs reduces NPC expense in Washington by $518,692.[180]

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[178] Staff Post-Hearing Reply Brief ¶¶ 68-72; ICNU Post-Hearing Reply Brief ¶¶13-19.

[179] Duvall, Exh. No. GND-5T at 46.

[180] Staff Initial Post-Hearing Brief, Appendix A at 1.

f. Sacramento Municipal Utility District (SMUD) Shaping Contract

127 The Sacramento Municipal Utility District (SMUD) purchases power under a contract from PacifiCorp, and the Company includes the cost of this contract in its GRID model.

128 *Positions of the Parties.* Staff argues that SMUD has some discretion regarding the timing of power deliveries under the contract, and the GRID model overstates the contract's cost by assuming that power will not be delivered in the months of April, May and June, when power costs are typically lower.[181] Using historic data of PacifiCorp's actual power deliveries to the SMUD, Staff produces an adjustment that lowers normalized net power costs, which takes into account deliveries that would be made in lower cost months.[182] Staff's adjustment lowers the Company's NPC by $554,460.[183]

129 ICNU also reduces the costs associated with the SMUD contract and adjusts the NPC by $458,223.[184] However, ICNU's rationale differs from Staff's adjustment in two ways.[185] First, ICNU decreases the quantity of energy taken under the contract, arguing that PacifiCorp overstates the energy delivered under the contract by 45,500 MWh, resulting in a reduction of Washington allocated power costs of $38,504.[186] ICNU also differs from Staff in that it uses the GRID model to calculate a dollar amount from the historic average of energy delivered to the SMUD under the contract.[187] Staff, on the other hand, uses a historic average to calculate a dollar

[181] Buckley, Exh. No. APB-1CT at 11 - 12.

[182] *Id*. at 13.

[183] *Id*. at 14.

[184] Falkenberg, Exh. No. RJF-1CT at 2.

[185] Falkenberg, Exh. No. RJF-1CT at 30 – 31; Exh. No. RJF-8CT at 3.

[186] *Id*.at 30 - 31.

[187] Falkenberg, Exh. No. RJF-8CT at 3.

amount, but does not run its adjustment through the model.[188] Should the Commission accept the reasoning behind Staff and ICNU's adjustments, they recommend that it order the Company to model the contract within GRID with deliveries more in line with historical deliveries.[189]

130 In rebuttal testimony the Company agrees with ICNU's adjustment to the level of allowed energy sales under the contract, which results in an increase to operating revenue of $19,039.[190] However, for three reasons, the Company disagrees with the use of historic data for modeling the SMUD contract costs.[191]

131 First, the Company asserts that, for normalization purposes, the model assumes that the third party (SMUD) that controls the timing of energy deliveries will maximize the value of the contract and take power at the time most economical to it.[192] The Company argues further that Staff and ICNU optimize flexible resources when the effect is to lower NPC, but chooses not to when it raises NPC. It contends that third party contracts should be treated consistently, and flexible resources should be optimized whether the Company is selling or buying power.[193]

132 Second, the Company argues the proposed adjustment departs from its process of modeling power costs on a normalized basis.[194] It claims that it cannot model constraints, forward price curves, or loads used by the counterparties because it cannot get that proprietary data and can only assume that all participants in the same market are rational and will exercise their contractual rights in a manner that lowers their costs.[195]

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[188]Buckley, Exh. No. APB-1CT at 13 - 14.

[189] Buckley, Exh. No. APB-1CT at 13 - 14, Falkenberg, Exh. No. RJF-8CT at 3.

[190]Dalley Exh. No. RBD-6 at 12.6.6.

[191] Duvall, Exh. No. GND-5CT at 36 - 40.

[192] Duvall, Exh. No. GND-5T at 37.

[193] *Id*. at 36.

[194] *Id*.

[195] *Id*. at 37.

133 Third, the Company contends that the model includes both the firm and the provisional features of the contract but that ICNU only addresses the firm feature in its adjustment.[196] The Company states that the contract's provisional feature allows SMUD the right to take provisional power under the terms of the contract and return the power to the Company the following year.[197] It argues that an examination of the contract's provisional and firm power features would support the GRID's conclusions as to power deliveries made to the SMUD under the contract.[198]

134 *Commission Decision.* We are asked again to select between the GRID model's results and an adjustment based on historic normalized data. A sharp contrast exists between actual deliveries under the SMUD contract and those projected by the GRID model, and the Company's statement that it cannot model constraints, forward price curves, or loads used by a third-party further weakens the support for using the model's results. When confronted with similar decisions, we give greater weight to actual results unless they are proven to be unreliable. The Company raised questions about how the SMUD would take power under the agreement but did not challenge the actual data on which Staff and ICNU rely.

135 We conclude that the Company did not demonstrate that the GRID effectively models the SMUD contract's actual impacts. The Company attempts to bolster its position by citing the importance of using SMUD's pattern of use under the provisional call option to determine SMUD's pattern of use under the demand portion of the contract. This argument is misplaced because PacifiCorp does not propose to use provisional sales in its net power costs. The real question is how to determine the effect of demand deliveries made under the SMUD contract. To answer this question, we conclude that Staff and ICNU's use of actual contract data to predict an outcome is correct and reasonably represents the SMUD's demand under the contract. [199]

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[196] *Id*. at 39.

[197] *Id*.

[198] *Id*.

[199] The Utah Commission has concluded similarly. *See* ICNU's Post-Hearing Brief. ¶62.

136 Accordingly, we require PacifiCorp to incorporate Staff's SMUD contact demand shape into the balancing adjustment required by this Order. We recognize that the amount of this adjustment cannot be calculated with specificity until all changes to the GRID model run are incorporated, but we estimate this adjustment will lower NPC expense by $554,460.

g. Colstrip Outage

137 PacifiCorp generates a significant amount of its power at its Colstrip coal plant, which like all plants, is subject to outages. The issue is how to compute the average outage rate for this plant as part of the Company's NPC.

138 *Positions of the Parties*. In 2009, PacifiCorp experienced a seven-month outage at Unit 4 of the Colstrip coal plant.[200] The Company proposes to use the period 2006 through 2009 as the base for computing the average outage rate for this plant.[201]

139 Staff believes that including the extraordinary 2009 period in the calculation of the plant's average outage rate would skew the outage average upward.[202] This would increase the Company's normalized net power costs, as the GRID model would seek to find replacement power, which is available but at a higher cost. In the alternative, Staff uses an average outage rate of eight percent in its calculation of Colstrip availability and contends that eight percent better represents the outage rates experienced by other utilities that own a share of the Colstrip plants.[203] Staff's adjustment reduces operating expense by $342,889.[204] ICNU also argues against including the 2009 outage in the plant's average outage calculation, concluding that the long outage in 2009 is "an extremely rare event" and not "likely to recur every

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[200] Colstrip Unit 4 is a baseload facility that provides low cost power.

[201] Duvall, Exh. No. GND-5T at 50.

[202] Buckley, Exh. No. APB-1CT at 15.

[203] *Id.* at 17. Here Staff testifies that its eight percent outage rate is similar to that experienced by Avista.

[204] Id. at 18.

four years.[205] Therefore, ICNU proposes to cap the length of the outage at 28 days,[206] resulting in an operating expense reduction of $376,492.[207]

140 In rebuttal testimony, the Company argues that Staff and ICNU's adjustments are unfair because they selectively remove data that would lower forced outage rates and thereby eliminate the opportunity for the forced outage rates to fluctuate with actual data.[208]

141 *Commission Decision.* The dispute before us is how to set an annual outage rate in light of a single, large, anomalous event. We agree with Staff that the purpose of establishing an annual outage rate is to represent expected outage levels during the rate year. PacifiCorp does not dispute that the approximately seven month outage is an anomaly. ICNU's proposal to remove all outages longer than 28 days addresses the issue, but lacks substantial justification.

142 While Staff's proposal is not elaborately described, we conclude that it is a better approach than either that proposed by the Company or ICNU and, most importantly, is more predictive of what may occur in the future. To calculate the impact of Staff's eight percent outage rate, we require the Company to re-run the GRID model using this outage rate for Colstrip Unit 4. Again, we recognize that the dollar amount of this adjust may vary as a result of other changes to the GRID model, and estimate that it will reduce NPC by $342,889.

h. Direct Current (DC) Intertie

143 PacifiCorp currently has long-standing agreement with the BPA that provides transmission capacity on BPA's Direct Current (DC) Intertie from the Nevada-Oregon Border (NOB) to the Buckley substation. PacifiCorp has BPA network

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[205] Falkenberg, Exh. No. RJF-1CT at 50.

[206] *Id.* at 50. Mr. Falkenberg cites, without elaboration, a recommendation by the Company in an Oregon proceeding as the basis his recommendation here.

[207] *Id*. at 2.

[208] Duvall, Exh. No. GND-5T at 49 - 50.

transmission service from the Buckley substation to its system loads, which enables it to make power purchases at the NOB.[209]

144 *Positions of the Parties.* PacifiCorp states that both Company-owned transmission capacity and transmission capacity provided by contracts with third parties are properly included in the West Control Area modeling so long as the capacity is needed to transmit power from and to locations in the West Control Area. Specifically, the Company contends that the costs of the BPA's DC Intertie are appropriately included in the GRID model.

145 Staff argues that the costs related to the transmission contract securing rights in BPA's DC intertie should be removed because the Company is unlikely to use the capacity during the year rates would take effect because of the high price of the power in California.[210] As support, Staff points to the fact that PacifiCorp does not include purchases at the NOB in its GRID model.[211] Therefore, Staff proposes a $1,057,130 reduction in NPC expense.[212]

146 ICNU agrees with Staff and recommends removing the DC intertie costs because the DC intertie contract is not used and useful,[213] and also argues that such purchases are unlikely to occur during the rate year.[214] ICNU proposes a $1,057,130 reduction in NPC.[215]

147 In rebuttal testimony, the Company argues that the DC intertie contract was entered into prudently and although the GRID model does not foresee energy transactions at the NOB during the test year, the prudency of the Company's actions should be

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[209] Buckley, Exh. No. APB-1CT at 18.

[210] *Id.* at 19.

[211] *Id*.

[212] *Id*.

[213] Falkenberg, Exh. No. RJF-1CT at 33 – 34.

[214] *Id*. at 34.

[215] Falkenberg, Exh. No. RJF-1CT at 2.

judged based on the information that was known at the time the contract was executed, not on hindsight.[216]

148 *Commission Decision.* PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.

149 Both Staff and ICNU testify that the contract is not expected to be used during the rate year to support the West Control Area, and thus no benefits are likely to materialize from the transmission capacity under the contract. The parties base their conclusions on the Company's failure to use the DC intertie capacity during the test year. As to its future use, they point to the absence of NOB contracts in the Company's GRID model as further support for their conclusion that the contract's capacity will not be used during the rate year.

150 We find Staff's and ICNU's testimony and arguments to be compelling. Generally, for a resource to be included in rates, it must be found to be used and useful. This is not to say that every component of the Company's system has to be used to provide service at all times.[217] However, the testimony here raises serious doubt as to the continued usefulness of the DC intertie capacity – doubt that PacifiCorp fails to address, much less resolve.

151 There is a point when facilities or even contracts such as this have no demonstrated or foreseeable need. It is at this point that such capacity should be retired or written off the books. We are not convinced that now is the time for such action, and we accept the Company's rationale that the DC intertie capacity could be useful in the future. The Company, however, must do more than state that the facility might be used at some unspecified time to justify including this resource in rates.

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[216] Duvall, Exh. No. GND-5T at 42.

[217] For example, peaking resources may only be used for short periods of time during a given period. We allow these in rates because the need for peaking capacity is fundamental to the efficient and reliable operation of the system.

152 If the contract is not being used by the Company, it has an obligation to market its available transmission capacity in an effort to recover some of its costs. The Company proffers no testimony along this line. For these reasons, we conclude that PacifiCorp failed to demonstrate that the DC intertie contract would provide benefits to Washington ratepayers during the rate year. Therefore, we adopt the adjustments presented by Staff and ICNU and reduce NPC expense by $1,057,130.

i. Idaho Point-to-Point (PTP) Transmission Contract

153 The Company has a point-to-point (PTP) wheeling contract with the Idaho Power Company. The issue arises concerning the extent to which the costs associated with that contract should be included in PacifiCorp's NPC.

154 *Positions of the Parties.* Staff uses confidential information to explain the terms of this contract, arguing that despite the benefits to both the western control area and the eastern control area.[218] PacifiCorp assigns all the contract costs to PACW.[219] Staff argues that this result is inappropriate and assigns only half of the Idaho PTP transmission cost to the PACW thus reducing NPC expense by $351,118.[220]

155 ICNU's adjustment likewise allocates 50 percent of the transmission contract's cost to the west control area based on the parallel treatment of other resources. It argues that because the Commission once disallowed benefits similar to those being realized by PACE in this instance, the Commission should disallow one-half of the Idaho PTP transmission contract costs at issue here.[221] ICNU explains that its adjustment amount differs from Staff's because it also excludes costs related to providing transmission service to isolated loads in Idaho.[222] ICNU's adjustment reduces expense by $363,988.[223]

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[218] The contract refers to the western control area as —PACW" and the eastern control area as —PACE."

[219] Buckley, Exh. No. APB-1CT at 20.

[220] *Id*. at 21.

[221] Falkenberg, Exh. No. RJF-1CT at 32. *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/UE-060817, Order 08, ¶¶ 53-54 (June 21, 2007).

[222] Falkenberg, Exh. No. RJF-1CT at 32.

156 In rebuttal testimony, the Company opposes the adjustment stating that it is a change to the WCA methodology and that *ad hoc* changes to the WCA should not be made until the five-year review of the methodology ordered by the Commission in Order 8 in Docket UE-061546.[224] The Company also updates its cost for the Idaho PTP contract rate arguing that if the forward price curves are updated, the matching principle requires that other costs also be updated.[225] The Company's update increases operating expense by $166,501.[226]

157 In its brief, the Company states that ICNU agreed that some PTP contract costs had been removed in the Company's initial filing.[227] There are two parts to the Idaho PTP transmission contract.[228] The first part relates to the Idaho PTP east portion and the Company removed these costs. The second part relates to the Idaho PTP west portion that is included in the Company's initial filing and is subject to ICNU's proposed adjustment.

158 The Company agrees with the portion of ICNU's adjustment that removes costs associated with providing transmission service to isolated loads in Idaho. PacifiCorp represents that removing those costs reduce operating expenses by $12,836.[229]

159 *Commission Decision.* We reject PacifiCorp's argument that the proposed adjustment is an *ad hoc* change to the WCA methodology that cannot be undertaken until the WCA's five-year review. We also reject the Company's assertion that the parties' adjustments run contrary to the principles underlying the WCA methodology. It is

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[223] *Id*. at 2.

[224] Duvall, Exh. No. GND-5T at 32 – 33. *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/UE-060817, Order 08, ¶¶ 53-54 (June 21, 2007).

[225] *Id.* at 17.

[226] Dalley Exh. No. RBD-6 at 12.6.6.

[227] PacifiCorp's Initial Post-Hearing Brief ¶ 77.

[228] Falkenberg, TR 655.

[229] Duvall, Exh. No. GND-5T at 26, Dalley Exh. No. RBD-6 at 12.6.6.

not inconsistent with that methodology to allocate costs of a resource between the PACW and PACE, so long as both divisions realize benefits. The costs of PACW resources included in NPC should be offset to reflect the benefits realized by the PACE when it uses PACW resources.

160 We conclude that Staff and ICNU's arguments for removing one-half the expenses associated with the Idaho PTP west portion of the transmission contract are persuasive. These parties demonstrate that both the PACW and PACE realize benefits under the contract, so the costs should not be assigned exclusively to the PACW. The Commission observes that the Company provides no evidence supporting the claim that half the costs associated with the west portion of the contract have been removed. ICNU's explanation at hearing that the adjustment is based on the west portion of the Idaho PTP contract costs is complete and convincing. We conclude that one-half of the Idaho PTP's *updated* costs, $753,840, should be removed from NPC. We also accept the undisputed adjustment to remove $12,836 in costs associated with the providing transmission services to isolated loads in Idaho prior to the removal of one half of the contract as ordered.

j. Price Update

161 The parties agreed to use the December 31, 2010, forward prices in the balancing adjustment to NPC.[230] We accept the use of these forward prices for the purpose of this case.

k. Logic Screen

162 *Positions of the Parties.* ICNU argues that there is a logic error in the GRID model that results in an excessive number of start-ups and shut-downs of the Company's gas fired resources."[231] Accordingly, ICNU proposes a different screening logic for the start-up (dispatch) of plants in GRID and proposes an accompanying adjustment outside of NPC to the variable O & M costs for thermal plants with dispatch affected by the proposed logic screening methodology.[232] ICNU's adjustment for logic screen, not including the O&M adjustment, reduces expense by $973,337.[233]

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[230] Exhibit 15C, Response to Bench Request No. 3.

[231] Falkenberg, Exh. No. RJF-1CT at 10 - 11.

[232] *Id*. at 14.

163 In rebuttal testimony, the Company accepts ICNU's proposed logic screen but does not accept that ICNU's conclusion that its screening logic changes incremental fixed O&M expenses included in the test year.[234] It argues that ICNU "provides no explanation of its adjustment or evidence to support it."[235] The net effect on revenues and expenses of the Company's adjustment is a reduction in NPC of $239,636.[236]

164 *Commission Decision.* We conclude that the undisputed modification to the logic screen is reasonable and should be accepted. We require the Company to use the modified logic screen in its balancing adjustment. However, ICNU failed to demonstrate that PacifiCorp made an incremental adjustment to O & M or its calculation of NPC to reflect the costs of additional dispatches. Therefore, we reject ICNU's adjustment to the O&M costs for thermal plants.

l. Eastern Market Sale

165 *Positions of the Parties.* ICNU states that PacifiCorp includes sales to the eastern control area when it models PACW power costs. ICNU proposes two adjustments that it argues would better reflect the benefits to the PACW of energy transactions between the western and eastern markets. ICNU's first adjustment is intended to capture the reliability benefits of utilizing excess generation to supply PACE. The second adjustment is intended to better capture the advantage of the price difference between prices at Mid-C and the eastern markets.[237] ICNU also contends that the GRID only models sales from the west control area to the east control area, and not purchases; does not properly consider hourly prices and off-peak sales; and only considers on-peak sales, ignoring opportunities for off-peak transactions that

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[233] *Id*. at 2.

[234] Duvall, Exh. No. GND-5T at 22, 55 - 56.

[235] *Id.* at 56.

[236] Dalley, Exh. No. RBD-6 at 12.6.6.

[237] Falkenberg, Exh. No. RJF-1CT at 18 - 19.

frequently exist.[238] ICNU's two adjustments increase operating revenue by $502,308.[239]

166 ICNU contends that Commission precedent supports its adjustments because the Commission decision on the WCA methodology supports the “indirect inclusion of eastside benefits and costs if purchases or sales between the control areas are economic.”[240]

167 The Company opposes these adjustments arguing that *ad hoc* changes to the WCA cost allocation methodology should not be allowed until the five-year review of the methodology ordered by the Commission is completed.[241] The Company also argues that ICNU's adjustment to eastern market modeling is flawed because it was done outside the GRID and ignores the impact of serving the assumed sale (the cost of electricity production). The Company proposes that if the Commission accepts this adjustment it should be run inside the GRID to determine its impact on NPC. The Company also asserts that ICNU proposes to adjust wheeling expense from the Colstrip plant, but allows the energy to pass through the transmission to the east side.[242] Finally, the Company argues that ICNU relies on benefits created after ICNU fabricates, within the model, an energy shortage for the eastern control area.[243] The Company recommends the Commission reject both adjustments.[244]

168 *Commission Decision.* We agree with PacifiCorp that ICNU did not provide adequate support for its first adjustment. ICNU's method for adjusting the model's operation

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[238] *Id*. at 16.

[239] *Id*. at 2.

[240] Id. at 16; *Washington Utilities and Transportation Commission v. PacifiCorp*, Docket Nos. UE-061546/ UE-060817, Order No. 08. ¶ 47 (June 21, 2007).

[241] Duvall, Exh. No. GND-5T at 32– 33.

[242] *Id*. at 35.

[243] *Id.*

[244] *Id.*

to derive a dollar figure for the value of the reliability benefit is not adequately explained.

169 We do find merit in ICNU's second adjustment. PacifiCorp's argument that it is an *ad hoc* adjustment to the WCA methodology misses the mark here as much as it did in our discussion of the Idaho point-to-point contract. The Company fails to defend its use of only on-peak hours in its eastern sales calculations. The Company also fails to defend or refute its use of monthly average hourly prices for the PACE, prices used to calculate the economics of a sale. We conclude that ICNU's second adjustment should be accepted thereby reducing NPC by approximately $225,248.

m. Eastern Control Area Transmission Costs- Colstrip East

170 *Positions of the Parties.* The Company splits in half the transmission costs of the transmission capacity from Colstrip to its entire system (both PACW and PACE) and includes half the costs of the entire transmission system in its Washington-allocated NPC. ICNU proposes a reduction in this wheeling expense to reflect the proportion of the transfer capacity from Colstrip to PacifiCorp that is attributable to connecting Colstrip to the PACW.[245] Utilizing a current topology map of PacifiCorp's GRID transmission, ICNU divides the Colstrip to PACW transfer capacity by the total Colstrip to PacifiCorp transfer capacity and uses that factor to allocate a portion of the total wheeling expense to the PACW. ICNU's adjustment reduces NPC expenses by $45,690.[246]

171 In rebuttal, the Company opposes the adjustment arguing that it is a change in the WCA methodology and that *ad hoc* changes should not be allowed. The Company recommends that changes be deferred to the Commission's five-year year review of the WCA methodology.

172 *Commission Decision.* As with the Idaho point-to-point contract, we are not persuaded by the Company's argument that adjustment is an *ad hoc* change to the WCA methodology that cannot be undertaken now. We reiterate that this position is contrary to the principles underlying the WCA methodology: that is, those burdens

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[245] Falkenberg, Exh. No. RJF-1CT at 31.

[246] *Id*.

align with benefits, and only those costs attributable to the western control area should borne by PacifiCorp' customers in that area. The costs of resources included in PACW net power costs should be proportional to the benefits the PACW realizes from those resources. ICNU presents a reasonable cost/benefit ratio based on the transmission capacity to the PACW and PACE. We accept ICNU's proportional split of transmission costs, thereby reducing NPC by $45,690.

n. Non-Firm Transmission

173 *Positions of the Parties.* ICNU proposes an adjustment to include non-firm transmission in the dispatch in GRID, as the Company has done in other states.[247] ICNU's adjustment reduces operating expense by $159,576. [248]

174 In rebuttal, the Company agrees to ICNU's adjustment but argues that if non-firm transmission is included, short-term firm transmission should also be included and both should be modeled the same way.[249] According to the Company, including both short-term firm and non-firm transmission *increases* the NPC by $274,089.[250]

175 *Commission Decision.* We reject both adjustments. There is insufficient evidence in this record to support including a non-firm transmission adjustment because there is no explanation of whether or not doing so in the same manner as short-term firm transmission is a more accurate modeling of the NPC. It is clear in the record who benefits from the adjustments, but this is not a sufficient basis for a decision. The Company's proposal to include short-term firm transmission with ICNU's proposed adjustment fails to address the question of how the model's accuracy is improved over the method the Company uses in its initial filing. The Commission seeks greater accuracy in the NPC modeling. Failing to find explanations of that in the record, we cannot accept these adjustments. The Company must file its balancing adjustment using the Company's initial calculation for short-term firm transmission and excluding non-firm transmission.

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[247] Falkenberg, Exh. No. RJF-1CT at 34.

[248] *Id*. at 2.

[249] Duvall, Exh. No. GND-5T at 16 - 27.

[250] Dalley Exh. No. RBD-6 at 12.6.4.

o. Planned Outage Schedule

176 *Positions of the Parties.* PacifiCorp uses actual outages in a four year period ending in 2009 to predict outages in the rate year.[251] ICNU proposes an adjustment based on revised timing for planned plant outages for Colstrip Unit 4 and Hermiston generation station.[252] ICNU argues that PacifiCorp plans outages for periods of least-cost replacement power but such timing is not reflected in the assumptions in GRID.[253] ICNU argues that the termination of the low cost gas contract that PacifiCorp uses to supply the Hermiston plant will change the operation of that plant.[254] Rather than operating continuously (due to the low-cost gas contract), the plant would operate on a more intermittent basis, more like the Chehalis plant.[255] ICNU models the Hermiston planned outage in late February and March; a time ICNU contends the economics of running the plant are least attractive.[256] ICNU's adjustment reduces operating expense by $429,712. [257]

177 In rebuttal testimony, the Company agrees to the outage schedule change for Colstrip Unit 4 but not for the Hermiston plant.[258] The Company states that accepting the Colstrip Unit 4 outage schedule reduces NPC by $119,286.[259] The Company argues that the Commission previously determined that it is not reasonable to assume that plant maintenance is timed to coincide with the period of lowest wholesale prices.[260]

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[251] Duvall, Exh. No. GND-5T at 29.

[252] Falkenberg, Exh. No. RJF-1CT at 47 - 48.

[253] *Id*.

[254] *Id.*

[255] *Id*.

[256] *Id*. at 48 - 49.

[257] *Id*. at 2.

[258] Duvall, Exh. No. GND-5T at 29 - 30.

[259] Dalley Exh. No. RBD-6 at 12.6.7.

[260] Duvall, Exh. No. GND-5T at 30; *Washington Utilities and Transportation Commission,* Docket No. UE-050482, Order No. 5 (December 21, 2005).

The Company asserts that the Hermiston plant's planned outage in 2011 is required.[261]

178 *Commission Decision.* We conclude that ICNU's assumption that the Company can postpone regularly-scheduled maintenance on the Hermiston plant in order to take advantage of the last few months of its gas contract is unsupported. ICNU provides no factual basis for the proposition that postponing Hermiston's maintenance is within the reasonable limits of the plant's maintenance requirements. Conversely, PacifiCorp argues convincingly that maintenance on the Hermiston plant cannot be delayed. We reject ICNU's proposed adjustment for the Hermiston plant.

179 We accept the undisputed adjustment regarding the proposed outage schedule for Colstrip Unit 4. The balancing adjustment should include the undisputed adjustment thereby reducing NPC by approximately $119,286. The balancing adjustment should also reflect retaining the Company's maintenance schedule for Hermiston. We recognize that the specific amount of this adjustment is interdependent on other changes to the GRID model run.

p. Jim Bridger Fuel Adjustment

180 *Positions of the Parties.* The Company argues that Jim Bridger mine costs have decreased due to increased production and efficiency in the underground mining operation, and those cost decreases are reflected in its NPC.[262]

181 ICNU adjusts costs associated with the Jim Bridger coal plant arguing that the plant experiences excessive outages due to poor quality fuel.[263] ICNU removes all management bonuses and other employee expenses arguing that these costs should not be included until plant performance improves because the Company has direct

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[261] Duvall, Exh. No. GND-5T at 30.

[262] Duvall, Exh. No. GND-1CT at 7.

[263] Falkenberg, Exh. No. RJF-1CT at 53 – 54.

control over coal production for the plant.[264] ICNU's adjustment reduces expense by $650,958.[265]

182 In rebuttal, the Company argues that the advent of less expensive underground mining at the Jim Bridger mine limits its capacity to blend coal to improve the coal quality and prevent outages.[266] The Company contends that it is inappropriate to remove costs associated with ―low-quality" coal from the underground mine, but accept the lower coal costs that result from the favorable economics associated with underground mining.[267] The Company asserts that it is evaluating a storage area for surges of poor quality coal so that it can engage in better coal mixing.[268]

183 *Commission Decision.* We acknowledge the concern that the Company's mining operations and facility design may be the cause of more frequent outages, but ICNU fails to make a plausible argument for disallowing certain personnel costs associated with the Jim Bridger mine. ICNU does not argue that the facility's underground mining operations are not beneficial even if the costs of increased outages are factored into the equation. Nor does ICNU argue that the Company failed to consider coal blending options when it shifted to an underground mining operation. ICNU simply asserts that outages have increased due to poor coal quality. Even if we assume that ICNU's assertion is true, ICNU does not base an adjustment on the costs associated with those outages. Rather, ICNU's adjustment centers on removing bonuses, meals, and sundries provided to workers at the facility. We conclude that ICNU has not demonstrated a reasonable nexus between the outages it claims are the purpose for the adjustment, and the costs it removes. Thus, we reject the adjustment.

184 We nevertheless are concerned with increased plant outages attributable to poor coal quality. The Company appears to acknowledge this problem in its discussion of its efforts to evaluate a storage area for surges of poor quality coal. In its next general

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[264] *Id.*

[265] *Id.* at 2.

[266] Duvall, Exh. No. GND-5T at 51.

[267] Duvall, Exh. No. GND-5T at 52.

[268] *Id.*

rate case, the Company must present evidence of its efforts to manage coal quality at the Jim Bridger plant and explain its efforts to mitigate the adverse effects of the poor coal quality attendant to its underground mining operations.

q. Minimum Loading and Deration Adjustment

185 To account for outages, GRID reduces an electrical generation unit's full capacity by "shrinking" the capacity of that unit. Thus, if there is a 20 percent outage rate at a 100 MW facility, the GRID model would view that as a plant with an 80 MW maximum capacity plant, and would not lower the plant's low-end operating range. The adjustment to the top range, but not to the lower range decreases the generation unit's range of variable output and thereby reduces its revenues in the model in response to short-term market prices.

186 *Positions of the Parties.* PacifiCorp states that if a generation unit is capable of cycling up or down through the usable range of its variable output during a short period of time, the Company's GRID model compares the operating cost with the market price to determine if it can take advantage of market price opportunities.[269] However, ICNU argues that the model under-represents the usable range of a generation unit's variable output.[270]

187 ICNU agrees that it is appropriate to represent outages by the "shrinking" or "deration" method, but ICNU proposes that the lower end of the generation unit's operating range also be lowered by the same percentage as the top range to more accurately represent the total variable range of the generation unit.[271]

188 Next, ICNU applies what it describes as a "better match" between the heat rate curve and the de-rated capacity of the plant.[272] ICNU explains, by example, that when the heat rate curve sized for a 100 MW unit is applied to a de-rated, 80 MW unit in

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[269] Duvall, Exh. No. GND-2 at 1 -2.

[270] Falkenberg, Exh. No. RJF-1CT at 56.

[271] *Id*. at 55 - 56.

[272] *Id*. at 56 – 57.

GRID, it artificially increases the heat rate curves and the efficiency of the unit is reduced.[273] ICNU's adjustment reduces expense by $299,897.[274]

189 In rebuttal testimony, PacifiCorp opposes both adjustments.[275] The Company argues that ICNU's adjustment understates the heat rate because:

> The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at one particular level of generation—its derated maximum capacity, with the assumption that the unit would have otherwise been dispatched at its stated maximum capacity in GRID if there were not the availability ―haircut". When the unit is dispatched at any level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level, whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs. [276]

The Company also argues that the minimum capacity in Grid Model is the technical limit below which the generation unit can't operate.[277]

190 *Commission Decision.* We move with some hesitation in this particular area of power cost modeling. Both approaches before us have merit, and both have flaws. Both methods alter the match of the heat rate to the plant output level. Ultimately, the Company has the responsibility to develop a computer model to determine NPC and the burden to demonstrate that the model is well-designed.

191 We conclude that, although this is a close call, we support ICNU's proposal because it appears to better represent the usable range of a generation unit and because it appears to better match the heat rate curve with the de-rated capacity of the plant.

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[273] *Id*.

[274] *Id*. at 2.

[275] Duvall, Exh. No. GND-5T at 54.

[276] *Id*. at 53 - 54.

[277] *Id*. at 55.

Accordingly, we adopt ICNU's adjustment and reduce NPC expense by $299,897. We will consider in a future case, however, an adjustment that reflects a more accurate middle ground between ICNU's and the Company's approaches to this issue.

r. Balancing Adjustment

192 *Positions of the Parties.* The Company, Staff, and ICNU agree that individual adjustments to the GRID model logic and inputs interact during power model runs and have interdependent effects on the final net power costs determined from the model.[278] Therefore, Staff and ICNU recommend that the GRID model be re-run with Commission-accepted adjustments in order to make a final determination of net power costs. The Company, Staff and ICNU agree that the GRID model needs to be re-run to reflect the most recent gas forward prices as of December 31, 2010.

193 *Commission Decision.* We conclude that PacifiCorp should re-run the GRID model with the forward prices as of December 31, 2010, and the net power costs adjustments approved above.[279]

2. Renewable Energy Credit Revenue (REC)

194 PacifiCorp generates electricity from renewable sources located in the west control area that qualify under RCW Chapter 19.285 as resources that can be used to meet the renewable portfolio standards (RPS) established by the statute. Washington's RPS require electric utilities to provide at least three percent of their load from renewable sources by January 1, 2012.[280] Electricity generated by qualified resources has added value in the form of renewable energy credits (RECs) that can be used to meet the RPS, sold, or, in some jurisdictions, banked for future use.[281] As a general rule today, PacifiCorp ―unbundles‖ RECs from the electricity output of its qualified

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[278] Duvall, Exh. No. GND-5T at 16, Falkenberg, Exh. No. RJF-1CT at 61, Buckley, Exh. No. APB-1CT at 4 – 5.

[279] Exh. No. 15C, Response to Bench Request No. 3.

[280] RCW 19.285.040.

[281] Another attribute of electricity generated by renewable facilities is the Production Tax Credit (PTC), which is a federal tax credit awarded to the facility owner for each kilowatt of electricity generated.

renewable generation, using electricity to serve load and either selling or banking the RECs[282].

195 *Positions of the Parties*. In its initial filing, PacifiCorp stated that during the test year it received $4,211,639 in revenue from the sale of RECs to other utilities.[283] However, PacifiCorp did not account for any of this revenue in its revenue requirement calculations. PacifiCorp's stated rationale for excluding this revenue was that it intended to ―bank" all eligible RECs in the future to help meet jurisdictional-specific renewable portfolio standards.[284] Insofar as Washington is concerned, this rationale depended in significant part on the Company's assertion that it ―anticipated legislative changes to Washington's RPS which would allow longer-term REC banking: and therefore would not sell excess RECs in 2011.[285] No such change occurred. Long-term banking of RECs is not allowed under current Washington law.[286]

196 In rebuttal testimony, PacifiCorp at least tacitly acknowledges these circumstances, agreeing with Staff that test year results should be relied on to determine an amount of REC revenue to be reflected in the Company's rates.[287] PacifiCorp proposed on rebuttal to reduce the Washington revenue requirement approximately $5.0 million, based on REC revenues of approximately $4.8 million. Staff had proposed reflecting somewhat less, about $4.2 million, but agreed in its brief with the Company's

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[282] There is no REC organized market in this region. Therefore, sales are generally consummated through bi-lateral negotiations.

[283] Dalley, Exh. No. RBD-1T at 9 – 10.

[284] Dalley, Exh. No, RBD-1T at 9 – 10, Dalley, Exh. No. RBD-3 at 3.5.

[285] Duvall, TR 298.

[286] Public Counsel Initial Post-Hearing Brief ¶ 62.

[287] Duvall, Exh. No. GND-5T at 3.

figure.[288] ICNU's initially proposed adjustment is in line with the amount to which PacifiCorp and Staff agree.[289]

197 Staff also recommends that the Commission order PacifiCorp to record as a regulatory liability all REC revenues from January 1, 2010, forward.[290] Staff recommends that the Commission address the ratemaking treatment of the deferred revenues in future general rate cases.[291]

198 The Company criticizes Staff's proposal to establish a regulatory liability account effective January 1, 2010, and characterizes it as retroactive ratemaking.[292] The Company also objects that such treatment would result in double-counting the REC revenues and violation of the matching principle.[293]

199 *Commission Decision.* The Commission considered the appropriate accounting and rate treatment for RECs for the first time in a proceeding concluded less than one year ago.[294] This proceeding is only the second occasion upon which such issues have been raised for determination in a litigated case.[295] In the prior contested case, the

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[288] Staff Initial Post-Hearing Brief ¶ 24. Some parties refer to this adjustment as an adjustment to —Green Tag" revenues. For the sake of consistency, we use the term renewable energy credit or REC because the parties are referring to the same revenues.

[289] Falkenberg, Exh. No. RJF-1CT at 2. ICNU argues in its Initial Post-Hearing Brief that test year revenues should be increased by $10 million, but this amount in not adequately supported, if supported at all, by the record in this proceeding.

[290] Foisy, Exh. No. MDF-1T at 10 – 11. Staff would also allow the Company to accumulate interest on the balance at its after-tax rate of return.

[291] Foisy, Exh. No. MDF-1T at 11.

[292] Duvall, Exh. No. GND-5T at 7.

[293] Duvall, Exh. No. GND-5T at 6.

[294] *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.,* Docket UE-070725, Order 03 (May 20, 2010). *See also id.* Order 05 (August 31, 2010) and Order 06 (October 26, 2010).

[295] Issues related to REC revenues were resolved on the basis of the Commission's approval of a —black box" settlement in PacifiCorp's most recent prior general rate proceeding. *Washington Utilities and Transportation Commission v. PacifiCorp.,* Docket UE-090205 (Order 09) (December 16, 2009). Order 09 and the rates that resulted from the Commission approved

Commission determined fundamentally that the REC benefits should go to all of PSE's retail ratepayers because they are the ones burdened with the responsibility of paying rates sufficient for the Company to recover all of the costs of the resources that generate the RECs, including a reasonable return on the Company's investment.

200 Beyond that fundamental determination, to which we adhere in this proceeding, questions concerning the proper accounting and rate treatment for REC proceeds proved challenging in the PSE docket. Indeed, it was not until Commission action on petitions for reconsideration[296] and on a joint proposal by the parties expressly invited by the Commission,[297] that these questions were fully resolved.

201 The Commission finds again in this case that neither the record nor the briefing on legal issues is fully sufficient to make all necessary determinations concerning the amount of RECs that should be returned to customers, various accounting issues, and the precise rate treatment that should be afforded REC proceeds received by PacifiCorp. Accordingly we will make in this Order only fundamental determinations concerning the treatment of REC proceeds. We also will provide some guidance to the parties while requiring further briefing and alternative or agreed proposals concerning certain matters, so that we can fully determine the details of how PacifiCorp will be required to treat REC revenues in terms of account and rates.

202 As previously indicated, we adhere in this proceeding to the basic principles discussed in Order 03 in Docket UE-070725 that require the proceeds derived from the sale of RECs to be returned to customers. In this proceeding, we determine further that these proceedings should be returned in the form of bill credits, identified separately on customers' monthly bills.

203 Since, in our view, questions remain concerning the timing and amounts on which PacifiCorp's REC proceeds should be based for the test, post-test, and rate periods implicated by this case, we will require PacifiCorp to establish a separate tracking

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settlement now are the subject of a formal complaint filed by Public Counsel and ICNU in Docket UE-110070.

[296] *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.,* Docket UE-070725, Order 05 (August 31, 2010).

[297] *Washington Utilities and Transportation Commission v. Puget Sound Energy Co.,* Docket UE-070725, Order 06 (October 26, 2010).

account for all REC proceeds received beginning January 1, 2009 (*i.e.* the beginning of the test year) and continuing through the rate year (*i.e.* until 12 months from the effective date of rates following approval of PacifiCorp's compliance filing in this docket). We also will require PacifiCorp to maintain the tracking account for subsequent periods.

204 In order to initiate the bill credit to customers coincident with the increase in rates they will experience based on our other determinations in this proceeding, we will accept for purposes of establishing 2011 credits the amount of REC revenues to which Staff and PacifiCorp agree, approximately $4.8 million.[298] This amount will be returned to ratepayers in 12 monthly credits in the same manner in which rate classes are assigned cost responsibility for the generation resources that produce REC revenue.

205 At the end of the rate year, PacifiCorp will be required to submit a full accounting of REC proceeds actually received during the preceding 12 months. This accounting will be considered in light of other information to determine if the amount of credits that should have been returned to customers exceeds or fall short of the estimated $4.8 million upon which the initial bill credits are based. In other words, the Commission will authorize a true-up of the initial credits that can be reconciled as credits are paid during the following 12 months.

206 At the end of the rate year and each subsequent annual period after the end of the rate year, PacifiCorp will be required to provide an estimate of the REC proceeds its expects to receive during the following 12 months. This is the amount on which credits during that period will be based. As at the conclusion of the initial period there will be a true-up at the end of each subsequent 12 month period. Having stated the basis upon which we resolve the issue for purposes of setting rates and establishing credits in this proceeding, we return to our earlier discussion of the concerns we have with the state of the record on the issue of RECs. In light of our concerns we require, as we did in Docket UE-070725, that the Company prepare and file within 60 days following the date of this Order a detailed accounting of all REC proceeds received during the period January 1, 2009, to the most recent date for which data are available. The report must include any updated forecast of

[298] It appears from Dalley, Exh. No. RBD-6 at 1.4, that the precise amount is $4,678,193, though that is not perfectly clear from the exhibit.

PacifiCorp's REC sales for the rate year. We direct the company to work cooperatively with Commission Staff as to the form and content of this filing so that it will prove most beneficial to the Commission.

207 We require this detailed accounting, in part, considering the disputed question of whether PacifiCorp should be required to include, in what we here describe as a tracking account, REC proceeds received during periods after the test year, including those received during the pendency of this proceeding. Staff proposed that REC proceeds received after January 1, 2010, be accounted for and established as a regulatory liability on the Company's books, the rate treatment of which could be determined in a future proceeding. Another possible starting date for such an account might be the date on which PacifiCorp made its initial filing in this proceeding, which put the rate and accounting treatment of REC revenues in issue. Other possible dates are conceivable, including the start of the rate year. We do not finally resolve these questions in this Order. We require additional briefing on the subject, and may require additional evidence. We will establish process and schedule for this by subsequent notice.

208 We also require the Company to file within 60 days after the date of this Order a detailed proposal for operation of the tracking mechanism going forward. This proposal should be developed in consultation with Staff and any other parties who wish to participate. The proposal must include a detailed discussion of the allocation method(s) the Company uses, or proposes to use, when allocating and reporting REC proceeds to Washington. If other parties disagree with PacifiCorp as to the details of the tracking mechanism or the allocation and reporting method(s) PacifiCorp uses or proposes to use, they may file alternative proposals.

3. SO_2 Emission Allowance Sales Revenue

209 PacifiCorp's initial testimony includes a 15-year amortization of current and past SO_2 emission allowance sales revenues in its cost of service.[299]

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[299] The Commission ordered the Company to use a 15-year amortization period for revenues associated with the sale of SO_2 emission allowances by Order 01 entered September 14, 1994, in Docket UE-940947.

210 Joint Parties propose that the unamortized balance of SO_2 allowance revenues at December 31, 2009, be amortized over five years instead of 15 years.[300] Joint Parties argue that five years is generally the most widely accepted amortization period for extraordinary events or recurring events with volatility.[301] They also assert that a five-year amortization period is more appropriate because it more timely credits customers' rates for the sales of SO_2 allowances.[302]

211 In rebuttal, the Company agrees with a five-year amortization period and proposes to increase NOI by $322,038.[303] The Company adds that the adjustment removes the sales that occur in the test period.[304]

212 *Commission Decision.* We accept the Company and Joint Parties' agreement to modify the amortization period established by prior order. The unamortized balance of SO_2 allowance revenues as of December 31, 2009, should be amortized over five years thereby increasing NOI by $322,038.

4. Temperature Normalization - Retail Sales

213 Temperature normalization is a ratemaking method that seeks to project an "average" level of electric sales (kWh) in the rate year by adjusting actual sales in the test year to reflect "normal" temperatures over a longer period of time. This tool, usually called a "temperature normalization adjustment," seeks to average out the rate peaks and valleys that can occur if actual temperatures are either above or below the average. Many customers in PacifiCorp's service territory in Washington use electricity for space heating, which increases their sensitivity to fluctuations in temperature.

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[300] Meyer, Exh. No. GRM-1T at 17.

[301] *Id*. at 18.

[302] *Id*. at 19.

[303] Dalley, Exh. No. RBD-6 at 12.0.

[304] Dalley, Exh. No. RBD-4T at 3.

214 *Positions of the Parties.* PacifiCorp includes a temperature normalization restating adjustment that decreases revenues for the residential class by $5,577,662.[305] In this case, it used the temperature normalization methodology agreed to by the parties in a previous rate case.[306]

215 Joint Parties argue that the Company's average actual usage per residential customer over the last five years is higher than the Company's temperature normalized customer usage for the test year.[307] They propose to decrease test year revenues by $79,439 (after the offset for additional fuel expense) as compared to what they state is PacifiCorp's $4,337,210 decrease.[308] Joint Parties state that it is proper to use actual data averaged over five years instead of temperature-normalized data to determine per customer use.[309]

216 In rebuttal testimony, the Company recommends rejecting the Joint Parties' adjustment pointing to Staff's testimony that the Company's residential class forecast demonstrates a good approximation of the relationship that exists between temperature fluctuations and electricity consumption.[310] The Company argues that the Joint Parties' calculation is faulty because it removes out-of- period adjustments and uses a five-year average without presenting either a rationale or precedent for doing so.[311]

217 In cross-answering testimony, Staff also opposes the Joint Parties' adjustment asserting that they should have used temperature-normalized usage, not actual usage,

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[305] Dalley, Exh. No. RBD-3 at 3.1.

[306] *See Washington Utilities and Transportation Commission v. PacifiCorp,* Docket UE-050684, Order 04 (April 17, 2006).

[307] Meyer, Exh. No. GRM-1T at 16.

[308] *Id.* at 16.

[309] *Id.* at 17.

[310] Duvall, Exh. No. GND-5T at 13.

[311] *Id*. at 13.

and that they fail to account for factors that offset the additional revenue they seek to impute to PacifiCorp.[312]

218 *Commission Decision.* We determine that the Joint Parties failed to support their recommendation that residential revenues should be based on the last five years of actual usage. The Company's temperature normalization methodology was included in a settlement adopted by the Commission, and that methodology's application to residential customer usage has proven to be quite accurate. We find that temperature normalization is a more appropriate method to estimate test year sales because many of PacifiCorp's customers use electricity for space heating and temperature may have a significant impact on customer usage.

219 Staff, moreover, compared usage for the 12-month period ending December 31, 2009, with the usage for the 12-month period ending June 2008. This comparison revealed a two percent increase in actual residential usage between these periods. However, a comparison of the temperature-normalized usage revealed that there was virtually no change in usage.[313] This comparison demonstrates that the increased usage can be solely attributable to differences in temperature. Simply put, the Joint Parties' proposed adjustment creates exactly the situation we seek to avoid: significant fluctuations in rates due to temperature differences.

220 Accordingly, we conclude that the Company's residential temperature normalization adjustment reflects an appropriate correlation between temperature fluctuations and residential electrical consumption.[314]

5. Temperature Normalization - Commercial Sales

221 The second aspect of temperature normalization relates to an adjustment to commercial sales, rather than residential sales.

222 *Positions of the Parties.* The Company's temperature normalization adjustment is a restating adjustment that normalizes revenues in the test period by comparing actual

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[312] Schooley, Exh. No. TES-4T at 4.

[313] *Id.* at 5.

[314] Novak, Exh. No. VN-1CT at 8; Staff's Initial Post-Hearing Brief at 5.

sales to temperature-normalized sales using the average weather over a 20-year rolling time period (currently 1990 through 2009).[315] This adjustment combines both residential and commercial sales using the methodology discussed in the previous subsection.[316]

223 While Staff agrees with the Company's methodology, it asserts that its application to commercial class customers produces unreliable results because it fails to explain 35.6 percent of the variation between temperature and commercial loads.[317] Staff's assertion is based on its claim that the Company's analysis does not show a sufficiently proximate relationship between temperature and electricity consumption.[318] Staff proposes removing the Company's temperature normalization adjustment for commercial sales only.

224 PacifiCorp recommends the Commission retain the commercial temperature normalization portion of its adjustment.[319] The Company argues that Staff's analysis should be rejected for three reasons. First, Staff's analysis is too limited because its sole focus is on the sensitivity coefficient or R-square value.[320] Second, the Company's methodology is consistent with Commission practice. Moreover, Staff agreed to this methodology in a previous case and now objects to its application to the commercial class. And finally, the Company's temperature normalization adjustment improves the accuracy of the combined load forecast.[321]

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[315] Dalley, Exh. No. RBD-1T at 8.

[316] Dalley, Exh. No. RBD-3 at 3.0.

[317] Novak, Exh. No. VN-1CT at 9.

[318] *Id*. at 8.

[319] Duvall, Exh. No. GND-5T at 10.

[320] The R square value is the statistical correlation between two variables; in this case, temperature and electricity consumption or load, that seeks to establish a coefficient over a period of ranges. For example, an R-value of .70 means that in 70 percent of cases, over a range of scenarios, the correlation is predictable and in 30 percent of cases it is not predictable.

[321] Duvall, Exh. No. GND-5T at 9 – 10.

225 *Commission Decision.* We agree with Staff that PacifiCorp failed to meet its burden to prove that its temperature normalization adjustment produces a reliable result that should be applied to the commercial class. The Company's adjustment does not demonstrate a proximate relationship between temperature and electricity consumption. Staff suggests that other analyses of the data could be performed to examine the causes of the wide variability in results, including evaluating subgroups within the commercial class.[322] This is an option the Company may wish to pursue in a future rate case. Our rejection of the Company's temperature normalization adjustment for the commercial class reduces revenue requirement by $965,319.

6. Restating and *Pro forma* Wage Increases

226 *Positions of the Parties.* The Company restates its test year wages for increases in labor costs to reflect salary increases for all employees during the test year. This adjustment increases the revenue requirement by $30,329.[323] PacifiCorp also proposes a *pro forma* wage increase that reflects union contract based wage increases effective after the test year, as of December 2010. This adjustment increases wages by $392,082. Union labor cost increases were adjusted using contract agreements whereas non-union and exempt employee adjustments are based on actual labor cost increases effective January 2009 and 2010.[324] The Company adjusts payroll taxes to reflect the impact of the changes. However, PacifiCorp did not adjust changes in workforce levels, employee benefits and incentives, or pensions. [325]

227 The Joint Parties oppose both the restating and *pro forma* wage adjustments.[326] With respect to the *pro forma* wage adjustment, they argue it should be disallowed because the Company did not consider all relevant factors including whether there are corresponding offsets to the wage increases such as changes in workforce levels or

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[322] Novak, Exh. No. VN-1CT at 11.

[323] Dalley, Exh. No. RBD-1T at 10.

[324] *Id*. at 10.

[325] Dalley, Exh. No. RBD-1T at 11.

[326] Meyer, Exh. No. GRM-1CT at 21-25, 29.

the Powerdale Hydro Removal adjustment.[327] With respect to the restating adjustment, they argue that 2009 wage increases for officer and exempt employees should be limited to the average increase granted to the other labor groups, or 2.07 percent. This adjustment would reduce required revenues by $128,366.[328]

228 In rebuttal testimony, PacifiCorp argues that both officer/exempt and non-exempt employees received an actual 3.5 percent wage increase in 2009, rather than the 2.07 percent increase provided to union employees.[329] It contends that it is unreasonable to limit non-union employees' wage increase to that afforded union employees because the negotiated agreements with union employees may have included offsetting benefits that make a direct comparison difficult. PacifiCorp also opposes the Joint Parties' proposal to eliminate the *pro forma* increases in labor costs arguing that these costs are known, measurable, and reasonable because the "Company implemented 2010 wage increases were slightly below market …" and only for employees earning a base salary below $100,000.[330] The Company notes that the Joint Parties do not object to the level of the proposed 2010 wage increase, but rather that other adjustments should be included in the revenue requirement. Finally, PacifiCorp stresses that the Joint Parties do not provide evidence supporting the "other adjustments."[331]

229 *Commission Decision.* We reject the Joint Parties' adjustments to 2009 and 2010 wage increases. We are not persuaded by their argument that the wage increase for non-union employees should be limited to the level of wage increase granted union employees. As PacifiCorp and Staff point out, the Joint Parties erroneously assume that all employees have the same overall compensation package thereby allowing a direct comparison of wage levels. Negotiated agreements with union employees may

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[327] *Id*. Meyer does not explain the Powerdale Hydro Removal adjustment, but we believe he is referring to the cost savings realized by the Company's retirement of the Powerdale hydroelectric facility. If so, the cost savings realized by the Powerdale adjustment are already reflected in the Company's filing.

[328] Meyer, Exh. No. GRM-1CT at 29.

[329] Wilson, Exh. No. EDW-3T at 12 - 13.

[330] Wilson, Exh. No. EDW-3T at 15.

[331] Wilson, Exh. No. EDW-3T at 16.

well consider other offsetting benefits such as increased medical benefits and pension or other retirement funding. In any event, there is no argument that the 2009 wages result in above-market compensation. These known and measurable wage increases are reasonable and should be approved.

230 We do not lightly reject the Joint Parties argument that all wage increases in 2010 should be eliminated because workforce reductions can offset any increases.[332] In this difficult economic time, utilities, like other businesses, should find ways to tighten their belts to minimize costs for the benefit of their customers and their investors. PacifiCorp, moreover, largely failed to show it is taking substantial actions to cut costs,[333] and the Company offered no convincing evidence that it is making aggressive efforts to reduce its administrative and general and other variable expenses. However, there are two reasons why, in this case, we cannot make the requested adjustments.

231 First, although it appears that workforce levels are lower, there is insufficient evidence in this record to quantify a potential offset to the revenue requirement. No witness of the Joint Parties offered an adjustment for us to evaluate or for the other parties to critique. Accordingly, we would be creating an adjustment out of an imprecise record on this point, a task we are reluctant in this instance to undertake.

232 Second, even if the proposed adjustment could be precisely quantified, the Joint Parties do not demonstrate that these are permanent work force reductions. The Company persuasively countered that the reduction in workforce levels is temporary and the slight downward trend is due to a hiring lag. PacifiCorp also states that while these positions are available and expected to be filled, many of these positions required specific skills, training, and education levels and the Company must take the time to find employees with appropriate qualifications.[334]

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[332] Dalley, TR 365.

[333] Reiten, TR 231 – 233; Reiten, RPR-1T at 5.

[334] Dalley, TR. 364 - 367. In any event, if we were to embark on our own adjustment based on reduced workforce numbers, the impact on Washington costs would be minimal. At most the record suggests a reduction of 65 employees in the full-time equivalent employees of the Company's system-wide workforce of 5,651. That would translate into approximately nine fewer employees allocated to Washington.

233 With respect to other ~~"o~~ffsetting" factors such as the Powerdale Hydro Removal, the Joint Parties fail to demonstrate any relationship between the expiration of the amortization period of this asset and the wage increases. As we noted in other proceedings, a party proposing an offset must net *all* changes in revenues and expenses utility-wide to determine whether a particular adjustment is offset.[335] In this case, the Joint Parties performed no such analysis.

234 Additionally, there is an inaccurate undercurrent in the Joint Parties' argument that these wage increases somehow benefit the higher echelon of PacifiCorp management. The majority of the employees receiving these wage increases are not executives but are professional, technical, support, and middle-management employees making less than $100,000 per year.[336]

235 The 2010 *pro forma* wage increases reflect known and measurable changes, and we approve them. We reiterate that the Joint Parties failed to make any argument that the 2010 wage increases elevated employee compensation above market-value.

7. Affiliate Management Fees

236 *Positions of the Parties.* PacifiCorp asserts that it was billed for $8.53 million in MidAmerican Energy Holding Company (MEHC) Washington-allocated management fees during the test year.[337] In its restated actual adjustment, PacifiCorp removes $1,053,029 leaving a total of $7.3 million.[338] PacifiCorp contends that $7.3 million is the maximum allowed under the MEHC Washington acquisition commitment.[339]

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[335] *Washington Utilities & Transportation Commission v. Puget Sound Energy,* Docket Nos. UE-090704/UG-090705, Order 11 (April 2, 2010).

[336] Wilson, Exh. No. EDW-3T at 13.

[337] Dalley, Exh. No. RBD-3 at 4.5. In its supplemental response to Bench Request No. 1, the Company states that it was actually billed $11.5 million in MEHC fees. The Joint Parties acknowledged that $11.5 million is the actual billed amount.

[338] Dalley, Exh. No. RBD-1T at 12; Exh. No. RBD-3, at 4.5.

[339] Dalley, Exh. No. RBD-1T at 12.

237 Joint Parties state that PacifiCorp pays an annual Management Fee to MEHC under an ―Intercompany Administrative Services Agreement."[340] According to the Joint Parties, the Agreement allocates certain MEHC costs to its subsidiaries.[341] They recommend disallowance of the following costs under the Management Fee as inappropriate to include in Washington rates:

- MEHC and MidAmerican Energy Company (―MEC") bonuses,
- costs of the Supplemental Executive Retirement Plan (SERP), and
- legislative costs and contributions.[342]

238 In rebuttal testimony, the Company accepts Joint Parties' removal of SERP and legislative expenses from the MEHC affiliate management fee on the basis that these costs are inappropriate to include in rates. The Company also removes capitalized expenses, the cost of air travel in excess of commercial-equivalent, and long-term incentive payments.[343] The Company argues that its rebuttal adjustments and the Joint Parties' adjustments should be applied against the total amount billed by MEHC rather than the $7.3 million that remains in Washington-allocated expenses after the Company removed amounts above the cap.[344] The combined effect of the Company's rebuttal adjustments reduces this amount to $7.11 million. It argues that because the $7.1 million is less than the level of the Merger Commitment cap of $7.3 million, no additional adjustment is necessary.[345]

239 *Commission Decision.* We conclude that Joint Parties misconstrue the merger commitment and apply the wrong methodology. Our order establishing the $7.3 million ―cap" simply means that *any* expenses over that level will be deemed unreasonable for Washington ratepayers to bear and will be disallowed. The

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[340] Meyer, Exh. No. GRM-1CT at 33.

[341] *Id*. at 33.

[342] *Id.* at 34.

[343] Dalley, Exh. No. RBD-4T at 5.

[344] *Id*. at 6 – 7.

[345] *Id.* at 7.

Company’s proposed management fee is well below the cap. Accordingly, we allow the $7.11 million in MEHC management fees. [346]

8. Annual Incentive Plan (AIP)

240 *Positions of the Parties.* PacifiCorp proposes to include $1.4 million in incentive compensation expenses arguing that its primary goal in determining employee compensation is to provide pay at the market average.[347] In addition, it contends that to encourage superior performance, a certain percentage of an employee’s compensation must be —at risk,”[348] its AIP provides employees with the incentive to perform at an above average level.[349]

241 PacifiCorp asserts that incentive compensation is a greater benefit to customers than compensation consisting solely of base compensation because a higher level of employee performance is achieved and the Company is able to attract and retain talented employees in a competitive market.[350]

242 The Company’s AIP provides performance awards based on: (1) the employee’s performance against individual goals; (2) the employee’s performance against group goals; and (3) success in addressing new issues and opportunities that arise.[351] Individual goals constitute 70 percent of the performance award and group goals account for the remaining 30 percent. PacifiCorp states that employees are not

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[346] That having been said, we are less than enthusiastic about some of the expenses included in the fee. During the hearing, there was considerable discussion about the bonus paid to MEHC’s chief executive officer (CEO). It is difficult for us to reconcile the general concept of —bonuses” with the Company’s assertion that it is undergoing —belt-tightening” measures to reduce costs. However, the amount of CEO bonus allocated to Washington ratepayers is $102,000. Stuver, TR. 435 – 36.

[347] Wilson, Exh. No. EDW-1T at 3.

[348] *Id.* at 4.

[349] *Id.* at 5.

[350] *Id*. at 5.

[351] *Id*. at 6.

evaluated on the basis of the financial performance of the Company.[352] PacifiCorp maintains a separate plan for executives that awards bonuses based on corporate performance; that plan is paid for by shareholders, not ratepayers.[353]

243 In this case, the annual cost of the AIP based on the twelve-months ended December 31, 2009, is approximately $29.8 million on a system-wide basis. It seeks to recover the Washington-allocated share of this expense of $1.4 million.[354]

244 The Joint Parties recommend that one-half of the incentive compensation expense, or $700,000, be disallowed.[355] The Joint Parties argue that the goals for the achievement of incentive compensation payments are not well-defined and many of the goals are not quantitative.[356] They state that PacifiCorp's AIP is based on the achievement of six group goals including: (1) customer focus; (2) job knowledge; (3) planning and decision making; (4) productivity; (5) building relationships; and (6) leadership.[357]

245 The Joint Parties assert that an acceptable incentive plan should include goals that improve or maintain PacifiCorp's existing operational performance in areas such as safety, managing operation and maintenance expenses, system reliability, and customer service.[358] They further note that some of the group goals enhance shareholder value, instead of providing tangible benefits to ratepayers.[359]

246 In rebuttal testimony, the Company states that ICNU recommended that the Commission disallow incentive compensation payments in PacifiCorp's last litigated

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[352] *Id.* at 7.

[353] *Id.* at 8.

[354] *Id*. at 8.

[355] Meyer, Exh. No. GRM-1CT at 9.

[356] *Id*. at 9.

[357] *Id*. at 10; Exh. No. GRM-5 at 1 – 2.

[358] Meyer, Exh. No. GRM-1CT at 10 - 11.

[359] Id. at 14.

general rate case in 2006.[360] The Commission rejected ICNU's argument that the payments were tied to business and financial performance and concluded that the payments were related to operational effectiveness, customer satisfaction, and safety.[361] The Company asserts that the current structure and goals of the AIP reflect the principles that the Commission stated in its approval of these costs in the 2006 case.

247 PacifiCorp reiterates that adopting the Joint Parties' position will result in employees being under-paid because the incentive compensation is not a —bonus,” it is an integral part of a competitive level of pay.[362] PacifiCorp contends that the Commission has generally left companies with the task of determining appropriate employee incentives and should reject the Joint Parties' proposal to disallow what it calls an arbitrary and unsupported 50 percent reduction to its AIP.

248 *Commission Decision.* As we decided in the last litigated case, we conclude that the AIP is an appropriate method of implementing —incentive-based” compensation. PacifiCorp has chosen an overall structure of employee compensation that includes both a base salary and a certain portion that is —at-risk,” or incentive compensation. By its very definition, incentive compensation is not a bonus or a level of pay in excess of the maximum compensation for a position. It is simply motivation for an employee to strive for the total compensation for his or her position by achieving certain individual and group goals.

249 There does not appear to be disagreement that this is a preferable means to structure employee compensation. In fact, during the hearing, the Joint Parties agreed that it was preferable to have employee compensation with an incentive component rather than a flat salary.[363]

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[360] Wilson, Exh. No. EDW-3T at 3. PacifiCorp's last litigated general rate case was Docket UE-061546.

[361] *Id.* at 3.

[362] *Id*. at 4.

[363] Meyer, TR 513 -514.

250 We do not wish to delve too deeply in to the Company's management of its human resources and the manner in which it determines overall compensation policy. Thus, we inquire only whether that compensation exceeds the market average, is unreasonable, and offers benefits to ratepayers. No party disputes that the total amount of compensation, adding the base salary and incentive compensation elements, results in a sum equivalent to the market average. The AIP is reasonable and its goals offer benefits to ratepayers. Accordingly, we reject the Joint Parties' proposed adjustment.

9. Legal Expenses

251 *Positions of the Parties.* The Joint Parties recommend that $48,931 be excluded from the Company's outside legal expenses.[364] The Joint Parties argue that, while it may be reasonable to allocate some expenses using an overhead allocation factor; other expenses should be limited to the jurisdiction in which the costs occurred.[365] They contend that legal expenses should not be calculated using the allocation factor and that $48, 931 in legal expenses be excluded because they were not generated in Washington.

252 PacifiCorp opposes this selective adjustment that departs from the normal method cost allocation set forth in the WCA. The Company notes that Staff also identifies cost categories that are being allocated to Washington customers on a system-wide basis rather by direct assignment.[366] However, rather than potentially increasing the revenue requirement by assigning costs to specific states, Staff proposes that the parties discuss ways to refine the allocation assignment of accounts on an overall basis in accordance with the WCA methodology.

253 *Commission Decision.* We agree with the Company and Staff that this proposal is too selective and should be rejected. We encourage the parties to engage in a dialogue that explores effective means to refine the allocation of *all* cost categories and

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[364] Meyer, Exh. No. GRM-1CT at 24.

[365] *Id*. at 24.

[366] Company Initial Post-Hearing Brief, ¶ ¶ 132 - 133, *citing* Foisy, Exh. No. MDF-1CT at 16, Dalley, Exh. No. RBD-4T at 21.

quantifies the revenue requirement impact of state-specific cost allocation versus the use of a system allocation factor.

D. Tax Adjustments

1. Repairs Deduction

254 *Positions of the Parties.* PacifiCorp proposes to normalize the cumulative effect of an Internal Revenue Service (IRS) approved change in its income tax accounting for certain capital assets. The change in tax accounting allows the Company to expense a cost for income tax purposes, instead of capitalizing and depreciating it for regulatory purposes.[367]

255 The IRS allowed PacifiCorp to adopt the “repairs deduction” method of accounting starting January 1, 2008.[368] However, it appears that the Company also recognized the “repairs deduction” retroactively for the years 1999 to 2007.[369] With that in mind, the Company also proposes that its adjustment be considered “non-final” in nature and requests that the $14,463,685 reduction to rate base be “adjusted if necessary after the Service [IRS] has completed its examination ....”[370]

256 Recognizing the impact of the change in its income tax accounting on its regulatory books, the Company recognized a deferred tax to account for the related book-tax timing difference. The timing difference is caused by the rapid recovery afforded by the repairs deduction for tax purposes and the slower depreciation for regulatory purposes. The increase in accumulated deferred taxes using average of monthly averages reduces the Company’s revenue requirement by $1.7 million.[371]

257 Staff agrees with the adjustment, but asserts that the Company’s recognition of the rate base impact reflects only half of the impact to accumulated deferred income

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[367] Fuller, Exh. No. RF-1T at 2.

[368] *Id.* at 3.

[369] Fuller, Exh. No. RF-3C.

[370] Fuller, Exh. No. RF-1T at 5 – 6.

[371] *Id.* at 5.

tax.[372] Staff proposes a $28,927,930 deferred tax deduction from rate base thereby decreasing the Company's revenue requirement by $3.5 million.[373]

258 In rebuttal testimony, PacifiCorp argues that deferred taxes are a source of interest-free funds that can be used to support of rate base investment. However, it contends that a utility cannot use the funds until it realizes the benefit. In this case, the Company argues it did not realize the benefit of the repairs deduction until it filed its income tax return in September 2009.[374] The Company argues that the deferred tax amount was properly recorded in 2009, but Staff improperly characterizes it as a prior year adjustment.[375]

259 *Commission Decision.* The parties do not dispute that PacifiCorp is expensing certain repair costs that it previously capitalized for tax purposes. Because the Company creates a book-tax difference by continuing to capitalize these costs, the parties also agree that the amounts should be normalized. Therefore, the sole issue is the timing of recognition and magnitude of the impact on rate base. The Company contends that it did not receive the benefit of the repairs deduction until it filed its federal income tax return in September 2009, so it reduces rate base by $14,463,685. Staff, on the other hand, calculates the full impact of the tax accounting change during the entire test year and reduces rate base by $28,927,370.

260 PacifiCorp argues that the Commission denied an adjustment in the 2009 Puget Sound Energy (PSE) rate case that is identical to the adjustment Staff proposed here.[376] The Company's reliance on that case is misplaced. In the PSE case, we rejected the argument that *no* adjustment could be made to rate base until after an IRS audit because the amount was not known and measurable. Here, according to the Company, the accumulated deferred income tax liability balance as of December 31,

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[372] Breda, Exh. No. KHB-1T at 23.

[373] *Id.* at 13 -14, 23.

[374] Fuller, Exh. No. RF-8T at 12.

[375] *Id*. at 13.

[376] *Washington Utilities & Transportation Commission v. Puget Sound Energy,* Dockets UE-090704/UG-090705, Order 11 at ¶¶ 193 – 197 (April 2, 2010).

2009, is $28,927,370.[377] Thus, the amount is both known and measurable. In addition, the IRS allowed the tax treatment in the PSE case long after the end of the test year. Here, in sharp contrast, the IRS allowed the tax treatment *during* the test year.[378]

261 We conclude that Staff is correct and we should accept its adjustment to reduce rate base by $28,927,370, which reflects the impact of the full year of the change. The repairs deduction is an ongoing difference in accounting that will be in effect for the same period as the rates set in this proceeding. The change is known and measurable. Accordingly, it is reasonable to normalize and reflect the impact as if it were in effect for the entire period. The impact of this adjustment reduces the revenue requirement by $1,822,309 in addition to the $1.7 million the Company has already recognized.

2. Interest Reserve

262 *Positions of the Parties.* The Company requests approval to establish a regulatory asset or liability to recover interest paid to or received from the IRS for any audit adjustments the IRS may make to the repairs deduction taken by the Company in its 2008 and 2009 income tax returns.[379]

263 Staff contends that although there is a risk of an adverse IRS audit, the exact level of risk is unknown. Therefore the Company's request to establish a regulatory asset or liability is premature.[380] Citing a prior Commission order, Staff argues that the Company can request an accounting order once any costs associated with an adverse IRS ruling become known and measurable. Staff asserts that the Commission would then consider the deferred costs in a future rate proceeding.[381]

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[377] Fuller, Exh. No. RF-5 at 1.

[378] In the PSE case, we rejected the proposed adjustment because "[T]he final disposition with the IRS is not known and the tax impact is in any event subsequent to the test year." Order 11 at ¶ 197.

[379] Fuller, Exh. No. RF-1T at 5.

[380] Breda, Exh. No. KHB-1T at 21 - 22.

[381] *Id.* at 21.

264 *Commission Decision.* We reject the Company's request to establish an interest reserve account. We agree with Staff that the Company's request is premature because, at this juncture, the Company does not have a definitive ruling from the IRS. This leaves us with no means to measure any risk the Company faces. PacifiCorp may request an accounting order when the results of any IRS audit are known and measurable.

3. Federal Income Tax: Normalization or Flow-Through

265 *Positions of the Parties.* The Company proposes in its originally filed case to adjust its books to reflect full income tax normalization accounting for regulatory rate-setting purposes. It has, with the exception of Allowance For Funds Used During Construction (AFUDC) equity,[382] abandoned the partial flow-through method traditionally used by the Commission.[383] The Company proposes to move to full normalization for practical reasons because income taxes are fully normalized in Oregon, Utah, and Wyoming which constitute 85 percent of the Company's total regulated operations. It asserts that full normalization would create a clear and unambiguous policy for the Commission and Washington would benefit from increased efficiency in the Company's income tax accounting and reporting processes.[384]

266 PacifiCorp further argues that ―a[]s a policy matter, the Company supports [full] tax normalization based on the matching principle and intergenerational equity."[385] The Company contends that its proposal matches tax benefits with cost responsibility and prevents customers who pay costs beyond the tax life of an asset from incurring a disproportionately higher tax rate than customers who pay over the life of the same asset.[386]

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[382] AFUDC is the cost of borrowed funds and equity used for construction purposes which is capitalized for later recovery. The deferred equity component is considered a temporary difference for general accounting purposes under *Accounting Standards Code* 980-740-25. The Company, however, proposes continued flow-through treatment of the book-tax difference.

[383] Fuller, Exh. No. RF-1T at 6.

[384] *Id.* at 6.

[385] *Id*. at 6 – 7.

[386] *Id.* at 7.

267 The Company requests approval to account for Washington-allocated income taxes on a fully normalized basis, except for AFUDC-equity, effective January 1, 2011.[387] To fully implement income tax normalization, the Commission would need to address the disposition of an income-tax regulatory asset associated with income tax flow-through.[388] Because the Commission has required the flow-through of tax-book timing differences that were not mandated to be normalized under the Internal Revenue Code, any conversion to full normalization must recognize a regulatory asset. The regulatory asset would represent the deferred tax amount associated with costs for which the rate payer has already received the benefit through a lower income tax expense.[389] However, because the Company is proposing to use flow-through accounting through December 31, 2010, PacifiCorp requests the Commission address the regulatory asset issue associated with its proposed transition to full normalization in its next rate case.[390] The change to full income tax normalization, other than the book-tax difference associated with AFUDC equity, reduces the Company's revenue requirement by $5,967.[391]

268 Staff recommends the Commission reject the Company's proposal because flow-through accounting passes the tax benefits to customers as the customer receives them."[392] Staff buttresses this position with four arguments. First, PacifiCorp did not fully address the impact of full normalization, so it is unknown since it would be considered in its next rate case. Second, PacifiCorp did not demonstrate the overall impact on ratepayers. Third, adopting full normalization for PacifiCorp could require the Commission to apply the same policy to all companies.[393] Finally, retention of

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[387] *Id.* at 8.

[388] *Id.* at 10.

[389] *Id.* at 10.

[390] *Id.* at 10.

[391] Fuller, Exh. No. RF-8T at 6.

[392] Breda, Exh. No. KHB-1T at 8.

[393] *Id.* at 22 – 23.

partial flow-through accounting is consistent with prior Commission decisions, two of three of which it cites involve PacifiCorp.[394] Staff's adjustment reduces the overall revenue requirement by $1,174,264.

269 In rebuttal, the Company argues that it did provide support for the impact for full normalization and[395] that it did address customer impact. It refers to a calculation in its direct testimony of the reduction in revenue requirement compared to flow-through accounting.[396] The Company counters Staff's argument that approval of full normalization for PacifiCorp will require application of the same treatment for all companies. Citing the same three cases as Staff, it argues that they are examples of the Commission approving normalization to varying degrees.[397]

270 In addition, the Company argues that it addressed all the issues it needs to address according to standard accounting methods: (1) the timing of the change; (2) whether the change is retrospective or prospective; and (3) the proper treatment of the flow-through effect from past periods.[398] Specifically, the change would take effect in 2011. It would be prospective, and the income tax effect would be reversed over the same time period as flow-through accounting. The Company recommends reversing the remaining book-tax differences over a fixed amortization period that would approximate the current time period to result in no net effect on customers.[399]

271 In support of its proposal, the Company argues that full normalization should not be prescribed prior to allowing temporary book-tax differences in rates.[400] It contends that it is necessary to —freeze and quantify" the flowed-through effects from prior

[394] *Id.* at 8.

[395] Fuller, Exh. No. RF-8T at 2.

[396] *Id*. at 4.

[397] *Id*. at 4 -5.

[398] *Id*. at 2, *citing* Robert L. Hane & Gregory Aliff, *Accounting for Public Utilities*, § 1701[5] (2008).

[399] *Id.* at 3.

[400] *Id. citing* Federal Energy Regulatory Commission Order 530.

periods for its book-tax differences for non-fixed assets. Citing a regulatory ―Catch 22," PacifiCorp claims it cannot quantify the flowed-through amount and propose an amortization period without Commission authorization to fully normalize and even then not until the close of the 2010 calendar year.[401]

272 In the alternative, if the Commission finds that additional analysis and discovery is necessary, the Company proposes that the Commission order PacifiCorp to file an accounting application within 30 days from the date of the final order and establish a six-month review period.

273 Finally, if the Commission rejects the Company's proposal to adopt full normalization, the Company argues that Staff's adjustment to remove the impact of full normalization from the *pro forma* financials is incorrect for two reasons. First, the Company contends that Staff's adjustment includes the impact of other state income taxes. Second, it does not exclude all deferred income tax expense and accumulated deferred income taxes for non-property-related book-tax differences that are not required to be normalized.[402] The Company argues that Staff does not remove deferred taxes related to certain book-tax differences that it believes are not consistent with the Commission's regulatory treatment of income taxes on a flow-through basis.[403] The effect of Staff's inclusion of the deferred taxes is a $6.4 million reduction to rate base.[404]

274 In supplemental testimony the Company further explains that the purpose of its adjustment to remove state income taxes is to recognize that although state taxes are considered a system-wide cost, they are not recoverable in Washington.[405] The Company also clarifies its proposal to use full normalization accounting for income taxes rather than the current partial flow-through basis adopted by the Commission.

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[401] Fuller, Exh. No. RF-8T at 4.

[402] *Id.* at 9.

[403] Fuller, Exh. No. RF-14T at 2.

[404] Fuller, Exh. No. RF-15.

[405] Fuller, Exh. No. RF-11T at 1 and 4.

275 In supplemental responsive testimony, Staff revises its proposed adjustment and states that, with the new more detailed information provided by the Company in its supplemental filing, it was able to —more accurately portray federal income taxes on a Commission basis.[406] Staff adjusts the Company's –per books" income taxes to what it argues is the correct method for ratemaking in Washington; (*e.g*., partial flow-through accounting).[407] Staff's revised adjustment results in a $5.4 million rate base reduction, with a $323,865 decrease in income tax expense.[408]

276 In supplemental rebuttal testimony, the Company argues that the Staff revised adjustment is inconsistent with its opposition to the Company's full normalization proposal. As evidence, the Company cites the Staff's use of normalized accounting for book-tax differences not required to be normalized by the Internal Revenue Code as well as the Staff's normalization of other items not explicitly approved for normalization accounting by the Commission.[409]

277 *Commission Decision.* Any decision to allow full normalization is a significant policy decision. We have used flow-through accounting for income taxes generally since liberalized depreciation was first introduced into tax law.[410] Thus, we must carefully evaluate the merits of this proposed policy change and first decide if there is ample evidence in the record to demonstrate that it will not harm ratepayers and not generate unwarranted revenue for the Company.

278 We conclude that PacifiCorp failed to meet its burden to prove that we should adopt full normalized accounting for income taxes. The Company explains that it cannot quantify the flowed-through amount and propose an amortization period without our

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[406] Breda, Exh. No. KHB-5T at 1.

[407] *Id.* at 1.

[408] *Id.* at 3.

[409] Fuller, Exh. No, RF-14T at 1.

[410] For example, the Commission states the company should be put on notice that any future use of liberalized depreciation on a normalized basis will be subject to immediate flow through if permissible under the tax law." *Washington Utilities and Transportation Commission v. Pacific Northwest Bell Company,* Cause No. U-9880, Second Supplemental Order at 15 (November 1969).

approval to fully normalize taxes; a situation it explains as a –regulatory Catch-22.”[411] We view this issue differently. The Company, in essence, is asking us to approve a –black box” whose contents would not be revealed until its next general rate case. That is unsatisfactory because it does not provide us with sufficient information to assess the validity of the request. The Company defies logic by arguing that an accounting-based number remains a mystery until we approve the methodology that generates that number. Accordingly, we reject PacifiCorp's proposal to convert to full normalized accounting for income taxes and adopt Staff's recommendation to adjust rate base.[412]

279 Our rejection of full normalization requires an adjustment to rate base. Because the Company's case is filed on a fully-normalized basis, it is necessary to revise the accumulated deferred income tax (ADIT) amount that is included in rate base. First, we address Staff's reduction to rate base resulting from removal of $5.4 million of prepaid income taxes from accumulated deferred income taxes. In support of its adjustment, Staff argues that all non-property items not protected by Internal Revenue Code normalization requirements (or as provided by Commission Order) should be flowed-through.[413] The Company does not contest this adjustment. Given our rejection of full normalization, we adopt Staff's recommendation to adjust total accumulated deferred income tax to reflect flow-through accounting.

280 Staff proposes a $6.4 million reduction to rate base related to deferred taxes the Company contends were flowed-through. In its analysis the Company treats the ADIT on these regulatory assets as flow-through and argues we should reject Staff's proposal, maintaining that the Commission did not explicitly authorize normalization of the tax benefits.[414] The Company contends that absent explicit authorization to normalize, tax benefits must be recognized on a flow-through basis.[415]

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[411] Fuller, Exh. No. RF-8T at 3 - 4.

[412] PacifiCorp asks in the alternative that we order the Company to file an accounting petition and establish a six-month review period. The Company, however, may file an accounting petition on its own initiative and thus does not need a Commission order requiring such a filing.

[413] Breda, Exh. No. KHB-5T at 4.

[414] Fuller, Exh. No. RF-14T at 2.

[415] PacifiCorp Initial Post Hearing Brief at 43.

281 We find the Company's argument lacking. These regulatory assets were deferred by specific Commission decisions. This dispute largely concerns the proper deferred tax treatment for the regulatory asset created by the Chehalis plant. In the Company's last general rate case, we accepted a settlement that established a regulatory asset for the Chehalis plant.[416] According to RCW 80.80.060(6) and WAC 480-100-435, the cost of the investment and related taxes are deferred, which we interpret to be consistent with normalization. Therefore, we accept Staff's recommendation to remove $6,404,813 in ADIT from rate base.[417]

4. Interest True-Up

282 In this case, all parties calculate the interest true-up adjustment by multiplying the rate base by the weighted cost of debt to determine the *pro forma* interest expense.[418] We approve and adopt this approach for purposes of this case.

E. Rate Base Adjustments

1. Working Capital/Jim Bridger Mine O & M/Current Assets

283 Working capital is a component of rate base that consists of cash and other short-term funds that can be used to finance non-utility plant items such as accounts receivables and certain inventories and supplies. It also helps finance the lag between billing and collecting for utility services. The dispute in this case concerns both the selection of a methodology to determine the amount of working capital to include in rate base and how to apply the methodology to a multi-state utility like PacifiCorp.

284 *Positions of the Parties.* The Company calculates working capital using the one-eighth of Operations & Maintenance (O&M) formula,[419] an approach commonly

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[416] *Washington Utilities and Transportation Commission v. PacifiCorp,* Docket UE-090205, Order 09 (December 16, 2009).

[417] The remaining assets, the Grid West loan was deferred in Docket UE-060703 and included as an uncontested adjustment in Docket UE-061546, PacifiCorp's last litigated general rate case. The Powerdale hydro plant and decommissioning costs were deferred in Docket UE-070624.

[418] Foisy, Exh. No. MDF-1CT at 15.

referred to as the ―formula method" or the 45-day method. The formula method divides total Washington-allocated normalized O & M expenses, less fuel and purchased power, by eight which is the approximate number of 45-day periods within a year.[420] In effect, this method assumes that a company always has 45 days worth of working capital in hand. This formula is also used by the BPA in the calculation of average system costs for investor-owned utilities.[421] Using the formula method, the Company's working capital is approximately $37 million, composed of $11.2 million in cash working capital, $11.3 million in current assets (including $7.8 million in materials and supplies and $3.5 million in fuel stock); and an additional $4 million in materials and supplies and fuel stock related to transferring the Jim Bridger Mine to rate base.[422]

285 Staff uses the Investor-Supplied Working Capital (ISWC) method to analyze the average of monthly averages for the test year on the basis of the total company balance sheet.[423] The ISWC method is a balance sheet approach of computing working capital; it is the net difference between current assets and current liabilities. Staff's approach involves a detailed analysis of the Company's assets and liabilities to determine the amount of working capital and takes the further step of determining its source. In operation, ISWC limits working capital to the amount provided solely by investors by systematically removing any non-investor provided working capital.[424] Staff proposes to remove all working capital, including the individually identified fuel stock and materials and supplies items, because such working capital is not investor-supplied.[425] The result is working capital of a negative $7.0 million.[426] Staff

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[419] Dalley, Exh. No. RBD-1T at 21. According to the Company, it used this method in its last two rate proceedings.

[420] *Id*. at 21.

[421] *Id*. at 21.

[422] *Id*. at 21.

[423] Schooley, Exh. No. TES-1T at 14.

[424] *Id*. at 10.

[425] *Id*. at 6.

[426] Schooley, Exh. No. TES-2 at 4.

criticizes the formula method because it assumes that investors supplied the working capital.

286 Staff also opposes the inclusion of the materials and supplies and fuel stock related to the Jim Bridger mine in rate base as working capital. It argues that because the Company has not provided that working capital, it should not be included.[427]

287 The Joint Parties support the use of a lead-lag study to compute working capital though they did not perform such a study for this case. Such a study analyzes who provides the flow of cash necessary to fund day-to-day operations.[428] If a utility must expend cash before the ratepayer pays for utility service, a shareholder provides the cash. However, if the ratepayer pays for service before the utility needs to pay expenses, the ratepayers provides the cash. They argue that a lead-lag study provides an adjustment to rate base allowing a utility to earn a return on the amount of cash necessary for operations that is supported by capital on which investors are entitled to a return.[429] They contend that electric utilities generally have negative working capital when a properly calculated lead-lag study is performed.[430] The Joint Parties criticize the Company's formula method because it assumes that a utility has a 45-day revenue lag and zero expense lag which can only produce a positive working capital amount.[431] Like Staff, the Joint Parties recommend that no working capital be allowed in rate base.[432]

288 In rebuttal, PacifiCorp argues that Staff is using essentially the same allocation methodology that the Commission rejected in its last litigated general rate case.[433] The Company contends that Staff's use of a total company approach in its analysis of

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[427] Schooley, Exh. No. TES-1T at 6.

[428] Meyer, Exh. No. GRM-1CT at 5.

[429] *Id*. at 5.

[430] *Id.* at 4.

[431] *Id*. at 5.

[432] *Id*. at 4.

[433] Dalley, Exh. No. RBD-4T at 18, referencing Docket UE-061456.

working capital fails because it includes significant Company investments not allocated to Washington under the WCA allocation methodology.[434] In addition, it opposes Staff's rate base removal of materials and supplies and fuel stock arguing that those items are necessary to maintain generation, transmission, and distribution functions and provide service to customers.[435]

289 The Company argues that the Joint Parties' proposed adjustment to working capital lacks ―any valid basis."[436] The Company notes that Joint Parties do not present a lead-lag study and primarily rely on their witness' experience that lead-lag studies for electric utilities generally show a negative working capital allowance.[437]

290 *Commission Decision.* We considered the issue of working capital in several prior rate cases beginning in 2006 when we rejected the Company's lead-lag study and Staff's ISWC method.[438] In the Company's last litigated general rate case, we also rejected both the Company's and Staff's working capital computations.[439] The issue is now before us again.

291 Of the three methods proposed, we are persuaded that the Staff's methodology is the most appropriate for this case. We agree with Staff that this dispute centers on the choice of the most appropriate methodology for working capital, rather than a disagreement on the actual calculation of the adjustment. Although the Joint Parties recommend the use of the lead-lag methodology, they did not submit any such study in this record and, therefore, we decline to adopt its use here.

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[434] *Id*. at 17.

[435] *Id*. at 16.

[436] Dalley, Exh. No. RBD-4T at 15.

[437] *Id*. at 13.

[438] *Washington Utilities and Transportation Commission v. PacifiCorp,* Docket UE-050684, Order 04 at 66 (April 17, 2006).

[439] *Washington Utilities and Transportation Commission v.* PacifiCorp, Docket UE-061546, Order 08 (June 21, 2007).

292 Regarding the Company's formula method, we agree with the arguments of Staff and the Joint Parties that it is deficient because it assumes that investors provide all funds necessary to the operations of the Company. As a result, we agree that this method will always produce positive working capital.[440] There are instances when the Company relies on non-investor supplied working capital. For example, non-investor working capital results from the lag between the receipt of a vendor bill and actual payment by the Company. Customer deposits are another common source of non-investor supplied working capital. Because the Company's method fails to recognize the different sources of working capital and separately identify the working capital that shareholders provide, we conclude that the formula method, as presented here, is not useful to calculate working capital.

293 On the other hand, Staff's ISWC method determines working capital by comparing the Company's assets to its invested capital while systematically removing non-investor supplied working capital. Staff can then determine to what extent investors have supplied additional capital that should be added to rate base. In other words, if PacifiCorp's invested capital exceeds its investments, the difference results in positive investor-supplied working capital.[441] Staff's analysis concludes that the Company's invested capital does not exceed investments and therefore, investors did not supply enough working capital.

294 The Company criticizes Staff's use of the total company balance sheet to calculate working capital.[442] Staff counters by pointing out that its method uses Washington-specific allocation factors based on the WCA method.[443] We are not persuaded by the Company's criticism of Staff's use of allocation factors it believes to be inconsistent with the WCA methodology. While we would prefer a rate case that presented only Washington-specific costs and revenues, the middle ground we have accepted is the

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[440] Schooley, Exh. No. TES-1T at 22, Meyer, Exh. No. GRM-1CT at 8.

[441] Schooley, Exh. No. TES-1T at 13.

[442] The Company argues that Staff's approach violates the Commission decision in UE-061546 and that working capital must be calculated on a WCA basis. *See* Dalley, Exh. No. RBD-4T at 14.

[443] Schooley, Exh. No. TES-1T at 9. We note that should we accept the Company's recommendation to reject Staff's ISWC methodology and, having rejected the methodologies proposed by the Company and the Joint Parties, the result would be the same – there would be no investor-supplied working capital adjustment to rate base.

WCA methodology used by the parties to allocate costs and revenues to Washington.[444] To determine working capital, both Staff and the Company start by analyzing the balance sheet accounts of the entire company. If positive working capital results from their analysis, then they allocate some portion of it to Washington. We are satisfied that Staff's method is consistent with the WCA's allocation principles and with our treatment of this issue for other multi-jurisdictional utilities.[445]

295 We next consider whether separately identified items such as materials and supplies and fuel stock should be included in rate base. We recognize that including these amounts in rate base allows recovery *of* the investment plus recovery of a return *on* the investment. We conclude that Staff properly excluded these items from rate base. Materials and supplies and fuel stock are consumed or built into permanent plant.[446] Thus, these items are essentially operating expenses or are transformed into permanent plant assets. To allow their recovery as either operating expenses or plant assets and also consider them working capital that should be added to rate base would allow double recovery of these items.[447]

296 In conclusion, we accept Staff's use of the ISWC method and its calculation of zero working capital. We also accept Staff's proposal to remove from rate base the materials and supplies and fuel stock related to the operations of the Jim Bridger Mine.

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[444] When we approved the WCA interjurisdictional cost-allocation method for Washington in Docket UE-060817, we required a five year review of the method, a review due in approximately June 2012. We expect the review to greatly refine the WCA to produce results that more closely represent Washington-only actual costs and revenues.

[445] We recognize that the application of any methodology in a multi-state region is challenging and that no method is perfect. We note the Company expects to complete a lead-lag study sometime in 2012 and we look forward to reviewing it for possible use in Washington the next rate case.

[446] Dalley, TR 355.

[447] Staff's Initial Post-Hearing Brief ¶ 121.

F. Cost-of-Service Study/Rate Spread/Rate Design

1. Cost-of-Service Study

297 Once the Commission establishes the Company's revenue requirement, the Commission must decide how the Company may generate that revenue in the rates it charges its customers. The first step in this process is to evaluate the Company's cost of service study (COSS) which identifies the costs caused by, or otherwise allocated to, each customer class.

298 *Positions of the Parties.* PacifiCorp prepared a functionalized Washington class COSS based on the historic 12-month period ended December 31, 2009, using the Company's annual results of operation.[448] The 2009 study modifies the previous methodology by revising the peak credit method which is used to classify production and transmission costs as either demand or energy.[449] The peak credit method formerly compared the cost of a current peaking resource, a Simple Cycle Combustion Turbine (SCCT), with the cost of a current baseload resource, Combined Cycle Combustion Turbine (CCCT), to determine the demand-related component.[450] All other costs are specified as energy related. In this case, PacifiCorp uses the capacity costs from its Firm Capacity Sales Agreement (Agreement) with BPA instead of its SCCT costs to determine the demand-related cost component.[451] The Company points out that it modified the peaking resource because it does not employ SCCT generating facilities in the West Control Area.[452] Thus, the new costs reflect actual Company operations within the West Control Area.[453] This modification results in 33 percent of costs being classified as demand-related and 67 percent of costs being classified as energy-relate. This increases the costs allocated to the

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[448] Paice, Exh. No. CCP-1T at 1 - 2.

[449] *Id.* at 2.

[450] *Id.* at 2- 3.

[451] *Id*. at 3. The cost of the BPA Agreement is $86.43/KW per year.

[452] *Id*. at 5.

[453] *Id*. at 5.

Residential Schedule and decreases the costs allocated to the industrial schedules.[454] Staff does not oppose the Company's use of the BPA Agreement as its peaking resource cost input.[455]

299 ICNU supports the Company's modification to its peak resource input asserting that it takes into consideration the actual peaking resource relied on by PacifiCorp in the West Control Area.[456] However, it disagrees with the use of 100 winter hours and 100 summer hours for allocating system demand-related costs arguing that this factor encompasses too many hours to accurately assign system demand costs.[457] ICNU contends that the peak demand factor should be determined using only those hours that are within 95 percent of the system peak hour or 48 summer hours and 23 winter hours.[458]

300 In rebuttal testimony, the Company opposes ICNU's proposal to calculate peak demand using only those hours that are within 95 percent of the system peak hour because it can produce volatility in results depending on the test period.[459] For example, PacifiCorp notes that had this method been in place during its last rate case then only 35 hours would have been included and none of those hours included the winter peak.[460] PacifiCorp recommends that we reject ICNU's adjustment because it is contrary to the principles of consistency and gradualism as it has the potential to create rate volatility and shift costs between customer classes. It further argues that ICNU's proposal is not based on analytical analysis and that it uses total system peak hours and not just the West Control Area to determine its results.[461]

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[454] *Id.* at 5-6.

[455] Schooley, TES-1T at 30.

[456] Schoenbeck, Exh. No. DWS-1T at 2.

[457] *Id*. at 2 - 3.

[458] *Id.* at 3.

[459] Paice, Exh. No. CCP-6T at 3.

[460] *Id.* at 3 – 4.

[461] *Id.* at 4.

301 In cross-answering testimony, Staff agrees that the cost of meeting peak demand should be shared by those using the system at that time but disagrees with ICNU that peak demand should be calculated using only 71 hours or 0.8 percent of the year.[462] Staff argues that it is more reasonable to calculate peak demand using 200 peak hours and note that this time period was specifically approved by the Commission in a previous PSE case.[463] Staff concludes that adopting ICNU's recommendation will further shift costs to residential customers from industrial customers.[464]

302 In summary, the sole area of dispute regarding the Company's COSS is the method used to calculate peak demand. ICNU seeks to narrow the peak demand calculation to those hours that fall within 95 percent of the system peak, instead of using the Company's proposed 200 peak hours. The Company and Staff disagree with ICNU's approach and assumptions.

303 *Commission Decision.* We accept the Company's unopposed revision to its COSS to replace a SCCT with the costs of its BPA contract. This revision synchronizes the calculation of demand-related and energy-related costs with the Company's actual operations. While we recognize that this modification results in more costs being allocated to residential customers, the change better represents actual system use by the affected classes. We believe this is a sufficient reason to make the change.

304 As to the issue in dispute, we reject ICNU's proposal to recalculate the COSS' peak demand calculation. ICNU's calculation would calculate peak COSS from only 71 hours annually, or approximately one-third of the hours considered by PacifiCorp. As we have in the past when presented with a precise revision to peak demand, we conclude that this is too narrow a range. [465] We agree with PacifiCorp that ICNU's

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[462] Schooley, Exh. No. TES-4T at 7.

[463] *Id. citing, Washington Utilities and Transportation Commission v. Puget Sound Energy, Inc*, Docket Nos. UE-920433/UG-920499/UE-921262, 9th Supplemental Order at 11 (August 17, 1993).

[464] Schooley, Exh. No. TES-4T at 8 - 9.

[465] *Washington Utilities & Transportation Commission v. Puget Sound Energy,* Docket Nos. UE-920433/UG-920499/UE-921262, 9th Supplemental Order at 12 (August 17, 1993). In that case, the Washington Industrial Committee for Fair Utility Rates (WICFUR) also proposed the use of only those hours within 95 percent of the system peak.

proposal could produce volatility in results depending on the test period.[466] While it is reasonable to allocate the costs of peaking resources based on the hours those resources will actually be used to serve load, the allocation method should be flexible enough to incorporate the variable peaks experienced in Washington. PacifiCorp experiences both a summer peak and a winter peak, and its proposal to include 100 summer hours and 100 winter hours to determine peak demand recognizes how resources are used. The Company points out that had ICNU's proposed methodology been in place during PacifiCorp's last rate case, only 35 hours would have been used to determine peak demand and none of those hours would have included the winter peak.[467] This example clearly demonstrates that ICNU's proposed methodology produces unreasonable results and should be rejected.

2. Rate Spread

305 Having allocated its costs among customer classes, PacifiCorp must assign recovery of those costs to each class. Each class generally should be responsible for the costs it causes, but public policy goals and other factors influence the extent to which the rates charged a particular class recover all of the costs allocated to that class. The Commission reviews this rate spread to ensure that it is fair, just, and reasonable.

306 *Positions of the Parties.* In its initial filing, PacifiCorp proposed to spread the rate increase to all rate schedules, other than street lighting, on an equal percentage basis.[468] For street lighting customers, the COSS results suggest only a small increase; the Company proposes a five percent increase for this schedule.[469]

307 Staff proposes higher than average increases in revenue for Residential Service (Schedule 16), Industrial Service (Schedule 48T), and Large General Service (Large General Service >1,000kW) schedules and lower than average increases for the commercial schedules, Small General Service (Schedule 24), Large General Service

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[466] Paice, Exh. No. CCP-6T at 3.

[467] *Id.* at 3 -4.

[468] Griffith, Exh. No. WRG-1T at 2.

[469] *Id*. at 3.

<1,000 kW (Schedule 36), and Agricultural Pumping Service (Schedule 40).[470] Staff proposes a minimal increase for the Street Lighting Service schedules.[471]

308 Using its recommended 10.58 percent overall revenue increase, Staff recommends a 12.5 percent increase for Residential, Large General Service >1,000 kW, and Dedicated Facilities, or 114 percent of the average increase.[472] For Small General Service, Large General Service <1,000 kW, and Agricultural Pumping Schedule, Staff recommends a 9.08 percent increase, or 83 percent of the average increase.[473] For the Street Lighting schedules, Staff recommends a one percent increase or about nine percent of the average increase.[474] Staff argues that its rate spread moves each schedule closer to full parity.[475]

309 ICNU supports the Company's rate spread proposal.[476] ICNU argues that while PacifiCorp overstated the cost of serving the industrial customers on Schedule 48T, it believes the Company's proposed equal percentage rate increase is reasonable.[477] ICNU contends that the Company's COSS demonstrates that all major customer classes are within 96 to 107 percent of parity.[478] It argues that the Company's proposal is consistent with the Commission's practice of approving equal percentage rate increases for classes with similar parity ratios and that it should be approved.[479]

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[470] Schooley, Exh. No. TES-1T at 3.

[471] *Id.* at 3.

[472] *Id.* at 31

[473] *Id.* at 31.

[474] *Id.* at 31.

[475] *Id.* at 35.

[476] Schoenbeck, Exh. No. DWS-1T at 6.

[477] *Id.* at 2.

[478] *Id.* at 6.

[479] *Id*. at 6.

310 Wal-Mart argues that the Company's rate spread proposal would move only one customer class closer to the actual cost of service and would create a larger gap between the actual cost of service and other customer classes.[480] Wal-Mart recommends that the Commission approve the Company's proposed rate increases for Partial Requirements Service and Street Lighting services and that the rate increases for Small General Service, Large General Service, and Agricultural Pumping be set at the jurisdictional average.[481] Wal-Mart proposes that the difference be collected from the rate schedules where rates are set at less than the cost of service.[482]

311 In rebuttal testimony, wherein the Company reduces its rate increase request from 21 percent to 17.85 percent, it Company concurs with Staff's rate spread recommendation proposing to spread the 17.85 percent rate increase consistent with Staff's recommendation.[483] The Company argues that this approach better reflects cost-of-service study results and applies smaller rate increases to Schedules 24, 36, and 40, and the lighting schedules that are currently paying more than the cost of service.[484] The other major rate schedules would receive a uniform percentage increase. Residential Service (Schedule 16) and Large General Service (Schedule 48T) would receive a 20.2 percent increase, equal to 113 percent of the average increase.[485] The commercial schedules, Small General Service (Schedule 24), Large General Service (Schedule 36), and Agricultural Pumping Service (Schedule 40) would receive a 14.7 percent increase, equal to 83 percent of the average increase.[486] The lighting schedules would receive a one percent rate increase.

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[480] Chriss, Exh. No. SWC-1T at 6.

[481] *Id*. at 6.

[482] *Id*. at 6.

[483] Griffith, Exh. No. WRG-7T at 2.

[484] *Id.* at 2.

[485] *Id*. at 2.

[486] *Id.* at 2.

312 In cross-answering testimony, Staff disagrees with ICNU that a 90 to 110 percent parity ratio is reasonable.[487] Staff argues that PacifiCorp's rate schedules have not moved closer to parity over the past five general rate cases.[488] Staff contends that industrial customers on Schedule 48T have been consistently below parity and commercial customers remain at parity ratios great than 1.0.[489] Staff reiterates that its recommendation will move customers toward parity.[490]

313 In its cross-answering testimony, ICNU argues that Staff's proposal is inconsistent with Commission decisions about rate spread for many years and should not be adopted.[491] ICNU points out that most major customer classes are within a few points of cost-based rates except for the street lighting class which is well above the class cost assignment.[492] ICNU supports the Company's proposal to assign a modest increase to street lighting and assign an equal percentage increase to other customer classes because they are relatively close to parity.[493] ICNU notes that Wal-Mart's approach is relatively close to the Company's proposal, but ICNU recommends that it be rejected for the same reasons Staff's proposal should be rejected.[494]

314 *Commission Decision.* In this case, the parties and all the customers testifying during our public comment hearing addressed the challenges presented by the difficult economic times faced not only by the state of Washington, but by the entire country. While it is true that each party used economic challenges to support a particular position on a specific issue, the concern with current economic conditions was pervasive.

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[487] Schooley, Exh. No. TES-4T at 10.

[488] *Id.* at 11.

[489] *Id.* at 11.

[490] Schooley, Exh. No. TES-4T at 12 -13.

[491] Schoenbeck, Exh. No. DWS-3T at 1.

[492] *Id.* at 3.

[493] *Id.* at 3.

[494] *Id*. at 4.

315 This concern reminds us that determining an appropriate rate spread requires consideration of a number of factors and is not the result of pure arithmetic calculations. Of course we consider the results of a valid COSS with the goal of ensuring that each customer class bears the burden of the costs it imposes on the utility. However we also consider principles of rate stability, gradualism, and the avoidance of rate shock.

316 Staff's rate spread, now supported by the Company, proposes higher than average increases for certain schedules and lower than average increases for others with the intent to move each customer class closer to full parity. For example, Staff's rate spread would result in residential and industrial customers receiving a rate increase of 114 percent of the average increase. We conclude that this is unreasonable and ignores the other principles that guide a determination of rate spread. Using PacifiCorp's COSS, all major customer classes are within 97 to 107 percent of parity. We conclude that the principles of gradualism and rate stability do not warrant moving these customer classes even closer to actual parity in the current economic conditions. Indeed, the composite effect of the revision to the Company's peak credit method, the proposed rate spread, and the revisions to rate design (which are discussed next) could well result in rate shock.

317 These principles of overall fairness, gradualism, and rate stability warrant spreading the rate increase in accordance with the Company's initial proposal: spreading the rate increase to all rate schedules other than street lighting, on an equal percentage basis. For street lighting customers, the Company's initial proposed five percent increase is reasonable.

3. Rate Design

318 Rate design is the final component of providing the Company with the opportunity to recover its authorized revenue requirement. Rate design determines how the Company structures the rates for each customer class.

319 *Positions of the Parties.* The Company asserts that its rate design proposals are consistent with the COSS and are sufficient to recover the proposed revenue requirement.[495] According to the COSS, the costs related to energy charges have

[495] Griffith, Exh. No. WRG-1T at 3.

increased more than the costs related to other rate components.[496] Therefore, the Company proposes larger increases to energy charges than demand charges.[497]

320 For General Service and Large General Service schedules, PacifiCorp asserts that the COSS indicates that larger increases are needed for energy charges than for demand, load size, and basic charges.[498] The rates for these schedules reflect the COSS results.[499] With respect to Agricultural Pumping Service, the COSS indicates that both the load size and energy charges should be increased.[500]

321 With respect to Street Lighting Schedules, the COSS indicates that only a small increase is warranted, so the Company proposes a five percent increase spread equally to all Street Lighting Schedules.[501] PacifiCorp proposes that the metal halide offering currently available in Schedule 52 be eliminated because the Company has no customers on these rates and does not anticipate any in the future.[502] Moreover, the Energy Independence and Security Act of 2007, Section 324 provides that metal halide fixtures cannot be manufactured after January 1, 2009.[503]

322 Staff recommends that the Commission accept PacifiCorp's proposed increases to basic charges and demand charges for non-residential schedules.[504] Staff asserts that most of the increase is to the energy charge.[505] Staff recommends that the basic charge and demand charges for Schedules 24, 26, and 48T be increased by the amount

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[496] *Id*. at 3.

[497] *Id.* at 3.

[498] *Id*. at 5.

[499] *Id.* at 5.

[500] *Id*. at 5.

[501] *Id.* at 5.

[502] *Id.* at 5 - 6.

[503] *Id.* at 6.

[504] Schooley, Exh. No. TES-1T at 36.

[505] *Id*. at 37.

proposed by the Company regardless of the revenue increase.[506] If the revenue requirement approved by the Commission is less than requested, then Staff recommends that the energy charge be reduced by a commensurate amount.[507]

323 ICNU does not support the Company's rate design for Schedule 48T and argues against increasing energy charges by a greater percentage than demand charges.[508] It contends that to do so would move Schedule 48T further from the cost-of-service. To avoid this result, it recommends that all Schedule 48T charges be increased by the same percentage regardless of the actual revenue increase granted by the Commission.[509]

324 Wal-Mart states that the Company's proposal to increase energy charges which shifts demand cost responsibility from lower load factor customers to higher load factor customers.[510] That is, the Company will over-recover demand cost from higher load factor customers and under-recover demand costs from lower load factor customers.[511] Wal-Mart argues that one benefit of collecting demand-related costs through demand charges is to reduce the risk of revenue instability as customers become more energy efficient, which makes demand-based revenues theoretically more stable than energy-based revenues.[512] Wal-Mart recommends that the Commission approve demand charges for Large General Service that represent 25 percent of the difference between the proposed rate design percentage of 16.7 percent and the proposed cost of service percentage of 29.3 percent, or approximately 20 percent of the total revenue requirement.[513]

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[506] *Id.* at 37.

[507] *Id.* at 37.

[508] Schoenbeck, Exh. No. DWS-1T at 7. In fact, ICNU posits that the rate design should reflect the converse.

[509] *Id.* at 8.

[510] Chriss, Exh. No. SWC-1T at 7.

[511] *Id.* at 8 -9.

[512] *Id.* at 10.

[513] *Id.* at 10.

325 In response to ICNU's and Wal-Mart's concerns, the Company revises its rate design for Large General Service, Small General Service, and Industrial Service by increasing all billing elements by a uniform percentage.[514] For Agricultural Pumping Service, PacifiCorp proposes to reflect the revised revenue requirement by increasing the Load Size Charge and Energy Charge by an approximately equal percentage. PacifiCorp proposes an increase of one percent for all street lighting schedules.

326 With respect to residential rate design, the Company proposes increasing the monthly residential basic charge from $6 to $9 to more closely reflect the COSS results which reflect a cost of $10.38.[515] PacifiCorp argues that increasing the basic charge to $9 moves closer to the cost-of-service while minimizing the bill impact.[516] The Company further argues that a $9 basic charge would continue to be one of the lowest among Washington utilities.[517] For energy charges, PacifiCorp proposes to retain the current inverted rate structure and apply an approximately uniform percentage increase to the two kilowatt-hour blocks.[518]

327 Staff recommends that the residential basic charge be increased from $6.00 to $7.50 and that the Commission accept the Company's rate design proposal for the other rate schedules.[519] Staff argues that because its proposed revenue increase of 10.58 percent is roughly half of the Company's proposed increase of 20.88 percent; the basic charge should be increased by one-half of the Company's increase or $1.50.[520] Staff notes that increasing the basic charge effectively reduces the energy charge.[521] Thus, the

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[514] Griffith, Exh. No. WRG-7T at 5.

[515] Griffith, Exh. No. WRG-1T at 4. The $10.38 figure would cover the Company's costs relating to meters, service drops, meter reading, and billing. *Id.* It is not designed to cover all fixed costs of the Company.

[516] *Id.* at 4.

[517] *Id.* at 4 – 5.

[518] *Id.* at 4.

[519] Schooley, Exh. No. TES-1T at 37.

[520] *Id.* at 37.

[521] *Id*. at 38.

rate impact of a basic charge increase affects a customer with low energy use more than a customer with high energy use.[522]

328 With respect to the Company's proposed increase in the residential basic charge, The Energy Project argues that factors other than the cost of service should be considered when determining the level of the charge.[523] First, The Energy Project contends that when consumption-based costs are diminished and transferred to fixed charges, customers lose the incentive to use energy efficiently.[524] Second, the higher fixed costs disproportionately impact low-use customers many of whom will be low-income customers.[525] The Energy Project recommends that the Commission reject any increase to the residential basic charge.[526]

329 In cross-answering testimony, Staff argues that, contrary to The Energy Project's assertions, energy charges exceeding nine cents per kWh give customers ample opportunity to conserve.[527]

330 In rebuttal testimony, the Company proposes to reduce its proposed increase to the residential basic charge to $8.50 from its originally proposed $9.00, and to retain the existing inverted rate structure.[528] The revised residential basic charge reflects the reduced revenue requirement sought in rebuttal. The Company disagrees with The Energy Project that increasing the basic charge sends an anti-conservation message. PacifiCorp argues that its rate structure supports an 18 percent increase in the energy charge and that this rate structure sends a proper conservation signal.[529]

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[522] *Id.* at 38.

[523] Eberdt, Exh. No. CME-1T at 13.

[524] *Id.* at 13.

[525] *Id.* at 14.

[526] *Id*. at 16 – 17.

[527] Schooley, Exh. No. TES-4T at 15.

[528] Griffith, Exh. No. WRG-7T at 3.

[529] *Id.*at 3.

331 *Commission Decision.* First, we accept PacifiCorp's revised rate design proposal for Small General Service, Large General Service, Industrial Service, and Agricultural Pumping Service. We conclude that this rate design adequately addresses the concerns raised by ICNU and Wal-Mart. We further conclude that the Company should be permitted to eliminate the metal halide offering currently available to Street Lighting customers in Schedule 52. As the Company notes, it does not have any customers taking service under Schedule 52 and does not envision any in the future.

332 Second, with respect to the residential basic charge, we conclude that the basic charge should remain at $6.00. While we acknowledge the Company's and Staff's intention to bring the basic charge more in line with their proposed rates for the class and to cover a number of the costs attributable to individual customers (such as those associated with meters, service drops, and billing), these are not the only considerations.

333 No one questions that we are still in the midst of difficult economic times. Under these circumstances in particular, many customers will view any basic charge increase as an additional increase above and beyond the rates approved in this Order. Those customers will not take into account the offsetting decrease in energy charges that would accompany an increase in their basic charge. Given the significant increase in rates approved in this Order, we do not want to wish to add to the rate burden already imposed on customers, whether real or perceived.[530] Not recovering some of the “basic” costs through the basic charge does not mean those costs will not be recovered; rather, those costs will just be recovered through the variable charges.

334 Finally, we share the Energy Project's concern that lower energy charges could result in reduced deployment of energy efficiency. While no party presented empirical evidence tying a reduced energy charge to the performance of the Company's energy efficiency program, there is sufficient testimony to establish a logical relationship between lower energy charges and customer interest in energy efficiency. As energy charges decrease relative to increased basic charges, a customer's energy efficiency investment recovery period is extended, which may negatively affect a customer's decision to invest in energy efficiency efforts.

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[530] A number of the comments submitted by ratepayers expressed concern about both the overall increase and the increase to the fixed charge. Exh. No. 8.

335 In conclusion, we find no compelling reason to increase the basic charge, and therefore, we will retain the current basic charge of $6.00.

4. Low Income Bill Assistance/Low Income Weatherization Assistance

336 *Positions of the Parties.* The Low Income Bill Assistance Program (LIBA) Program credit is available to low-income customers through Schedule 17 and is funded through a Schedule 91 surcharge.[531] The Company proposes changes to LIBA that will increase the funding level, expand eligibility criteria, and reduce administrative overhead.[532] PacifiCorp proposes to increase the Schedule 91 surcharge collections by the same percentage amount as the price change proposed for residential customers in this case.[533]

337 The Company also proposes to allocate 70 percent of the surcharge to increase the low income bill credit and 30 percent to increase the qualifying low income customer program cap.[534] PacifiCorp also proposes that income eligibility should be increased from 125 percent to 150 percent of the Federal Poverty Level (FPL) to provide a benefit to households with a limited income that do not qualify for other services.[535]

338 In addition, PacifiCorp proposes to require bi-annual, rather than annual, recertification of eligibility arguing that bi-annual recertification will decrease program costs and provide greater benefits to eligible customers.[536]

339 Staff accepts the Company's proposals regarding LIBA, but Staff recommends that the Schedule 91 Surcharge be set at 21 percent even if the percentage increase approved by the Commission for the residential class is less than that amount.[537]

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[531] Griffith, Exh. No. WRG-1T at 6.

[532] Reiten, Exh. No. RPR-1T at 6.

[533] Griffith, Exh. No. WRG-1T at 6, Exh. No. WRG 2 at 19.

[534] Griffith, Exh. No. WRG-1T at 7.

[535] *Id*. at 7.

[536] *Id.* at 7.

340 The Energy Project proposes to increase LIBA funding in an amount greater than the level of rate increase granted PacifiCorp for its residential customers.[538] It also expresses concern with splitting the incremental increase in LIBA benefits between deepening the existing discount and serving additional customers because the program needs to provide a meaningful benefit to each participating household.[539]

341 With respect to the Company's proposal to modify the program's income eligibility threshold, The Energy Project points out that such a result could reduce the level of benefits for households at the bottom of the poverty ladder.[540] It further notes that last year Washington elected to retain LIHEAP[541] eligibility at 125 percent of the FPL rather than increasing it because of the number of households at the 125 percent level that could not get served.[542] Moreover, The Energy Project argues that having a different eligibility standard for LIBA and LIHEAP funding sets up a double standard that is difficult to explain.[543] In the alternative, it suggests that all parties work toward developing an alternative delivery mechanism before the next rate case.[544]

342 With respect to modifying the certification process to every other year, The Energy Project applauds PacifiCorp's intent to serve more customers, but argues that the proposal hinders agencies' ability to provide income certification because it effectively reduces administrative support.[545] This "feast or famine" approach makes it impractical for agencies to process approximately 5,000 households one year and

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537 Schooley, Exh. No. TES-1T at 40.

538 Eberdt, Exh. No. CME-1T at 4.

539 *Id*. at 4.

540 *Id*. at 8.

541 LIHEAP is the federal Low Income Home Energy Assistance Program. *Id.* at 5 and 8.

542 *Id*. at 8.

543 *Id*.at 8.

544 *Id.* at 8 - 9.

545 *Id.* at 9.

few or none the next.[546] In addition, The Energy Project asserts that the fee PacifiCorp currently pays agencies for certification does not cover the costs of certification and recommends that the certification fee be increased to $65 per household.[547]

343 Finally, The Energy Project argues that this is a critical time for PacifiCorp to increase its investment in the Low-Income Weatherization Assistance program (LIWA).[548] It notes that The American Recovery and Reinvestment Act (ARRA) added $59 million to Washington's normal Department of Energy Weatherization Assistance Program (WAP) from 2009 - 2011 argues that PacifiCorp should increase LIWA funding by $500,000 to fill the void that will be left when ARRA funding expires.[549]

344 In rebuttal testimony, the Company supports Staff's proposal to increase the Schedule 91 surcharge by 21 percent regardless of the actual amount of residential increase approved by the Commission, citing the benefit that this result would confer upon low-income customers.[550]

345 The Company also accepts The Energy Project's proposal to retain the income guideline at 125 percent of FPL noting that revision could increase administrative costs if the income guideline is different than the one used for LIHEAP.[551]

346 PacifiCorp disagrees with The Energy Project's proposal to use all LIBA funds to increase the discount without increasing the cap on the number of program participants.[552] It also opposes The Energy Project's proposal to continue annual

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[546] *Id.* at 11.

[547] *Id.* at 10.

[548] *Id.* at 14.

[549] *Id.* at 14 -16.

[550] Eberle, Exh. No. RME-1T at 3.

[551] *Id.* at 5.

[552] *Id.* at 5.

certification of program participants.[553] During the past program year, agency administrative costs accounted for 21 percent of total program costs and participants' discount accounted for 79 percent.[554] The Company argued that if administrative costs can be decreased, more households will receive program benefits.[555]

347 The Company also opposes The Energy Project's recommendation to increase the administrative fee from $48 to $65 per household certified because it does not believe the increase is in the best interest of its customers.[556] However, it recommends that the Commission Staff convene a collaborative meeting with the parties to determine how the certification process can be modified to lower agency costs and increase benefits to people in need. [557]

348 PacifiCorp opposes The Energy Project's proposal to increase LIWA program funding by 50 percent, or approximately $500,000.[558] The Company budgets $1 million annually for reimbursements to its partnering agencies, but the agencies do not bill PacifiCorp for the full budgeted amount.[559] In recent years, reimbursements include $617,263 in 2007, $532,700 in 2008, $491,986 in 2009, and $346,523 through September 2010.[560]

349 In cross-answering testimony, Staff recognizes The Energy Project's concern with biannual certification by suggesting that agencies recertify one-half of the participants for two years and one-half for one year.[561] Staff contends that this compromise would

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[553] *Id.* at 6.

[554] *Id*. at 6.

[555] *Id*. at 6.

[556] *Id.* at 7.

[557] *Id.* at 7.

[558] *Id.* at 8.

[559] *Id.* at 8.

[560] *Id.* at 8.

[561] Schooley, Exh. No. TES-4T at 17.

spread workload over two years and avoid the administrative problems The Energy Project identifies.[562]

350 Staff is not opposed to the principle that PacifiCorp fairly compensate agencies for administering the program but argues that The Energy Project's support for increasing administrative reimbursement is insufficient.[563] Staff notes that The Energy Project only provided information for one agency for one month, so Staff supports retaining the reimbursement rate of $48 per certified customer.

351 Staff opposes The Energy Project's proposal to increase LIWA funding by $500,000.[564] Staff argues that the applicable tariff sheet is not before the Commission, that the Commission should conduct a comprehensive review before modifying the benefit charge, and that it was understood that ARRA funding was temporary.[565]

352 In cross-answering testimony, The Energy Project objects to Staff's characterization of LIBA as a ―tax” because helping customers living at the economic margin of society provides system-wide benefits in the form of enhanced cash flow, reduction in bad debt expenses, and reduced collection costs.[566]

353 In cross-answering testimony, Staff concurs with PacifiCorp's proposals program eligibility and certification. The Energy Project also reiterates its concerns with those modifications to the program.[567]

354 *Commission Decision.* Overall, we accept the undisputed recommendations regarding the LIBA program. We agree that the Schedule 17 surcharge should be increased by 21 percent to serve more customers and to greater offset the revenue increase

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[562] *Id.* at 17.

[563] *Id.* at 17.

[564] *Id.* at 19.

[565] *Id.* at 19.

[566] Eberdt, Exh. No. CME-5T at 4.

[567] *Id.* at 7 – 9.

approved by this Order. We also retain income eligibility at 125 percent of the FPL because we are concerned that different eligibility levels for LIHEAP and LIBA could create confusion and increase administrative costs.

355 With respect to the proposed modification to LIWA funding, we reject The Energy Project's proposal to increase funding by 50 percent, or an additional $500,000. The evidence clearly demonstrates that reimbursements under this program have not come close to reaching the current budgeted amount. We encourage The Energy Project, PacifiCorp, or any other party to come forward with such a request if it can demonstrate that a funding increase is necessary to ensure immediate success of the program. Until that time, we will not increase funding.

356 With respect to the disputed issues concerning the allocation of LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees, we are not convinced that these are appropriate matters for resolution by the Commission through the adjudicative process. These matters should be addressed through negotiations and contracts between PacifiCorp, The Energy Project, and the agencies that actually administer the program, Blue Mountain Action Council, Opportunities Industrialization Center of Washington, and Northwest Community Action Center (collectively referred to as the ―agencies"). These entities share the same goals with respect to LIBA and are interested in serving the customers eligible for the program in a manner that maximizes the benefits of the program and fairly compensates the agencies for administering the program.

357 We are also disinclined to address these matters in this proceeding because the adjudicative process, by its very nature, promotes disagreement and relies upon advocacy to fully flesh out issues in dispute. As a result, the hearing room does not advance the discussion necessary to resolve the policy questions raised by the parties. We believe these issues would be more effectively addressed through a collaborative process that includes PacifiCorp, The Energy Project, Staff, and the agencies.

358 Accordingly, we decline to modify the current allocation of the LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees. Instead, we require PacifiCorp to meet with The Energy Project, Staff, and the agencies to discuss these issues. We recognize the importance of these issues and do not want them to languish, so we require Staff to report to us the results of the collaborative process within six months of the date of this Order.

FINDINGS OF FACT

359 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

360 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas and electrical companies.

361 (2) PacifiCorp provides electric utility service to customers in Washington.

362 (3) The rates proposed by tariff revisions filed by PacifiCorp on May 4, 2010, and suspended by prior Commission order, are not just, fair or reasonable.

363 (4) PacifiCorp's existing rates for electric service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

364 (5) PacifiCorp requires relief with respect to the rates it charges for electric service provided in Washington State.

365 (6) The rates, terms, and conditions of service that result from this Order, based on a revenue deficiency of approximately $38 million are fair, just, reasonable, and sufficient.[568]

366 (7) The rates, terms, and conditions of service that result from this Order are neither unduly preferential nor discriminatory.

[568] *See* Appendix A.

367 (8) PacifiCorp has met its obligations under the following commitment made at the time MEHC acquired the Company: Commitment 37 – Long-term Debt Yield Reduction. Commitment 37 is complete.

CONCLUSIONS OF LAW

368 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

369 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

370 (2) PacifiCorp is a —public service company" and an —electrical company" as those terms are defined in RCW 80.04.010 and as those terms are used in Title 80 RCW. PacifiCorp is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

371 (3) The rates proposed by tariff revisions filed by PacifiCorp on May 4, 2010, and suspended by prior Commission order, were not shown to be fair, just or reasonable and should be rejected.

372 (4) PacifiCorp's existing rates for electric service provided in Washington are insufficient to yield reasonable compensation for the service rendered and should be adjusted to provide the Company a reasonable opportunity to recover its full revenue requirement.

373 (5) PacifiCorp should have the opportunity to earn an overall rate of return of 7.81 percent based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 9.8 percent on an equity share of 49.1 percent.

374 (6) PacifiCorp should be authorized and required to make a compliance filing reflecting rates for electric service that will recover a revenue deficiency of approximately $38 million and that otherwise satisfies the requirements of this

Order. PacifiCorp and Staff are required to determine the precise amount of the Company's revenue requirement, which may vary slightly from the stated amount due to computational refinements during review of the compliance filing.

375 (7) PacifiCorp should be authorized and required o make a compliance filing reflecting net power costs with the adjustments approved in this Order. PacifiCorp and Staff are required to determine the precise amount of net power costs during review of the compliance filing.

376 (8) PacifiCorp's compliance filing should include tariff sheets that increase the Schedule 91 surcharge by 21 percent to increase funding of the Company's low income billing assistance program.

377 (9) PacifiCorp's compliance filing should include a separate tariff item for Renewable Energy Credits to be reflected on residential customers' monthly bills.

378 (10) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

379 (11) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

380 (12) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

381 (13) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

O R D E R

THE COMMISSION ORDERS:

382 (1) The proposed tariff revisions PacifiCorp d/b/a Pacific Power & Light Co. filed on May 4, 2010, and suspended by prior Commission order, are rejected.

383 (2) PacifiCorp is authorized and required to make a compliance filing including such new and revised tariff sheets as are necessary to implement the requirements of this Order. The stated effective date of the revised tariff sheets must allow Staff a reasonable opportunity to review the compliance filing and to inform the Commission whether Staff finds the revised tariff sheets fully conform to the requirements of this Order.

384 (3) PacifiCorp must file within sixty days of this Order a detailed accounting of Renewable Energy Credit (REC) revenues received since January 1, 2009, and a detailed proposal for the REC tracking mechanism as required in Section II.C.2 of this Order. These filings, as well as additional filings required to be made in connection with the REC tracker, as discussed in the body of this Order, must be made in this docket as compliance filings or reports, as required under WAC 480-07-880(1) and (3).

385 (4) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

386 (5) Commitment 37 – Long-term Debt Yield Reduction, made at the time MEHC acquired PacifiCorp is deemed to have been fulfilled and the Commitment is complete.

387 (6) PacifiCorp must meet with The Energy Project, Staff, and the affected agencies in a collaborative process to discuss the current allocation of the LIBA surcharge collections, the interval for eligibility certification, and the level of administrative fees. Staff must report the results of this process within six months of the date of this Order.

388 (7) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

DATED at Olympia, Washington, and effective March 25, 2011.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

JEFFREY D. GOLTZ, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

COMMISSION DETERMINATION OF REVENUE REQUIREMENT

APPENDIX A
COMMISSION DETERMINATION OF REVENUE REQUIREMENT

LN NO	A	B	C	D: COMMISSION NOI Impact	E: COMMISSION Net Rate Base Impact	F: COMMISSION Commission's Revenue Requirement Impact
1	Per Books	Adj No.		$46,232,662	$751,399,887	$20,087,225
2	Adjustments					
3	REVENUE					
4	Temperature Normalization	3.1	U	($4,357,889)	$0	$7,030,214
5	Revenue Normalizing Adjs.	3.2	U	(69,998)	2,751,332	$459,568
6	Effective Price Change	3.3	U	8,061,401	0	($13,004,777)
7	SO2 Allowances	3.4-12.1	C	332,038	(2,334,188)	($829,738)
8	Green Tag Revenues	3.5-12.5	C	(2,737,565)	0	$4,416,282
9	Wheeling Revenue Adjustment	3.6	U	60,438	0	($97,500)
10	Remove Commercial Sales	3.7	C	598,382	0	($965,319)
12	O & M					
13	Misc. General Expense	4.1	U	28,780	0	(46,428)
14	General Wage Increase-Annualization	4.2	U	(18,800)	0	30,328
15	Proforma General Wage Incr	4.3	U	(243,032)	0	392,063
16	Pension Curtailment	4.4	U	474,858	0	(766,048)
17	Affiliate Management Fee	4.5-12.3	C	59,810	0	(96,486)
18	DMS Removal Adjustment	4.6	U	3,198,895	472,406	(5,100,987)
19	Removal Non-Recurring Entries	4.7	U	127,808	0	(206,182)
20	Remove MEHC Severance	4.8	U	397,117	(306,376)	(679,236)
21	SERP Expense	12.2	C	110,289	0	(177,920)
22	Advertising Expense	12.4	C	1,178	0	(1,900)
23	Combined Cycle O&M Adj	4.9	U	0	0	0
25	POWER					
26	Net Power Costs-Restating	5.1	U	7,150,053	0	(11,534,576)
27	Net Power Costs-Proforma	5.2-12.6	C	(22,135,735)	0	35,709,710
28	Electric Lake settlement	5.3	U	(98,983)	(212,583)	132,897
29	BPA Residential Exchange	5.4	U	(5,216,329)	0	8,415,063
30	James River Royalty Offset	5.5	U	766,070	0	(1,235,836)
31	Removal of Colstrip #3	5.6	U	274,987	(8,160,130)	(1,471,725)
33	DEPRECIATION/AMORTIZATION					
34	Hydro Decommissioning	6.1	U	0	(264,083)	(33,272)
36	TAX ADJUSTMENTS					
37	Interest True Up	7.1-12.9	C	(1,229,228)	0	1,983,010
38	Accum. Deferred Income Tax Factor Cor	7.2	U	0	(5,199,035)	(655,037)
39	Renewable Energy Tax Credit	7.3	U	5,638,736	0	(9,096,496)
40	Mailin Midpoint Adjustment	7.4	U	291,667	(510,417)	(534,830)
41	WA-FAS 109 Flow-Through	7.5	U	(5,532,834)	0	8,925,653
42	AFUDC - Equity	7.6	U	75,955	0	(122,532)
43	Public Utility Tax Adjustment	7.7	U	257,639	0	(415,627)
44	Remove Def State Tax Expense	7.8	U	2,199,228	1,099,614	(3,409,286)
45	Current Year Def Inc Tax Normalization	7.9	C	323,865	(5,401,575)	(1,203,020)
46	Medical Deferred Tax Expense	7.10	U	(170,464)	0	274,995
47	Avg Bal for Accum Def Inc Tax-Property	7.11	U	0	(9,873,199)	(1,243,945)
48	WA Low Income Tax Credit	7.12	U	20,962	0	(33,816)
50	RATE BASE					
51	Cash Working Capital	8.1-12.8	C	0	0	0
52	Jim Bridger Mine Rate Base	8.2	C	0	30,678,372	3,865,233
53	Environmental Remediation	8.3	U	(37,050)	261,509	92,718
54	Customer Advances for Const	8.4	U	0	23,143	2,916
55	Miscellaneous Rate Base	8.5	U	0	(7,864,275)	(990,837)
56	Cont Miscellaneous Rate Base	8.5.1	U	13,847	1,697,440	191,526
57	Removal of Colstrip #4 AFUDC	8.6	U	17,991	(441,006)	(84,587)
58	Powerdale Hydro Removal	8.7	U	109,264	462,824	(117,954)
59	Trojan Unrecovered Plant Adj	8.8	U	99,958	748,258	(66,979)
60	Customer Service Deposits	8.9	U	(22,103)	(2,980,496)	(339,862)
61	Chehalis Reg Asset- WA	8.10	U	(1,861,470)	9,488,085	4,198,376
62	Repairs Deduction	8.11	C	0	(14,463,670)	(1,822,309)
63	Current Assets	8.12	C	0	(11,300,254)	(1,423,743)
65	PRODUCTION FACTOR					
66	Production Factor Adjustment	9.1-12.7	U	50,606	(729,160)	(173,507)
67	(Cont) Production Factor Adjustment	9.1.1-12.7.1	C	136,616	(46,772)	(226,284)
68	Combined Cycle O&M Adj	4.9	U	0	0	0
70				$33,379,620	$728,995,651	$37,999,196

71				
72	CONVERSION FACTOR			0.61988
73				
74	RATE OF RETURN CALCULATION	% OF CAPITAL	COST	WEIGHTED
75				COST
76				
77	EQUITY	49.10	9.80	4.81
78	LONG-TERM DEBT	50.60	5.89	2.98
79	SHORT TERM DEBT	0.00	0.00	0.00
80	PREFERRED	0.30	5.41	0.02
81				
82	TOTAL	100.00		
83	WEIGHTED AVERAGE COST OF CAPITAL			7.81%
84				
85			PROFORMA INTEREST	
86			ADJUSTMENT	
87				
88	RATE BASE		$728,995,651	
89	WEIGHTED COST OF DEBT		0.0298	
90	PROFORMA INTEREST		21,724,070	
91	ACTUAL INTEREST		25,236,151	
92	INCREASE (DECREASE) INTEREST EXPENSE		(3,512,081)	
93	FEDERAL INCOME TAX		1,229,228	
94	NET OPERATING INCOME		(1,229,228)	
95				
96				
97			GROSS REVENUE	
98			REQUIREMENT	
99			INCREASE	
100				
101	PROFORMA RATE BASE		$728,995,651	
102	AUTHORIZED RATE OF RETURN		7.81%	
103	NET OPERATING INCOME REQUIREMENT		$56,934,560	
104	PROFORMA NET OPERATING INCOME		$33,379,620	
105				
106	RECOMMEDED INCREASE (DECREASE)		$23,554,941	
107	CONVERSION FACTOR		0.61988	
108	INCREASED REVENUE REQUIREMENT		$37,999,194	

GLOSSARY

TERM	DESCRIPTION
AIP	Annual Incentive Plan.
CAEW	Control Area Energy – West. An allocation factor used in the WCA interjurisdictional cost allocation methodology. The CAEW factor is a 100 percent energy weighting of Oregon, Washington and California retail loads based on each states' share of the west control area temperature normalized annual megawatt hours. .
DC Current Intertie	Direct Current Intertie
Deferral Account	An accounting convention that allows a utility, with authorization from the Commission, to record costs during one period for possible recovery in rates during a subsequent period. Permission to defer costs does not carry a guarantee that the costs will later be allowed in rates or that unamortized deferral balance will be allowed to earn a return as rate base.
GRID	Generation and Regulation Initiatives Decision model. A computer model that PacifiCorp uses to estimate future power costs.
ICNU (Industrial Customers of Northwest Utilities)	Industrial Customers of Northwest Utilities is a regional organization whose members are large industrial customers of various utilities, including PacifiCorp.
ISCW	Investor-supplied working capital. The average amount of capital provided by investors in the company, over and above the investments in plant and other specifically identified rate base items, to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. The accounting definition of working capital is current assets less current liabilities. According to Goodman, the accounting definition is seldom used in rate regulation.[569]
LIBA	Low income bill assistance. This is a ratepayer-funded program to provide financial assistance to qualified PacifiCorp customers who have difficulty paying their utility bills.
LIWA	Low Income Weatherization Assistance program.

[569] Goodman, Leonard Saul, The Process of Ratemaking, Vol. 2, pp. 828-838 (Public Utilities Reports, Inc., 1998).

MEHC	MidAmerican Energy Holding Company. A part of the Berkshire Hathaway group of companies, MEHC purchased PacifiCorp in 2005 in a transaction the Commission examined and approved in Docket UE-051090
NOI	Net operating income. A company's operating income after operating expenses are deducted, but before income taxes and interest are deducted.
REC	Renewable Energy Credit.
ROE (return on equity)	The rate of earnings realized by a utility on its shareholders' assets, calculated by dividing the earnings available for dividends by the equity portion of the rate base. The Commission establishes an authorized rate of return for recovery in rates.
SCL	Seattle City Light
SERP	Supplemental Executive Retirement Plan.
SMUD	Sacramento Municipal Utility District.
WCA (West control area) allocation	An interjurisdictional cost allocation methodology that eliminates all resources and loads in PacifiCorp's east control area, though it does include resources that serve but are not physically located in the WCA states (Washington, Oregon, California).