STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO	:	**09-0306 and 09-0309**
	:	
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY, d/b/a AmerenCIPS	:	**09-0307 and 09-0310**
ILLINOIS POWER COMPANY, d/b/a AmerenIP,	:	**09-0308 and 09-0311**
Proposed general increase in electric and gas delivery service rates.	:	**(Consolidated)**

INITIAL BRIEF OF THE ILLINOIS INDUSTRIAL ENERGY CONSUMERS

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<u>INITIAL BRIEF OF THE ILLINOIS INDUSTRIAL ENERGY CONSUMERS</u>

A diverse group of large electricity and natural gas consumers**,** Air Products & Chemicals, Inc., Archer-Daniels-Midland Company, ASF Keystone, Cargill, Inc., Caterpillar Inc., ConocoPhillips, Enbridge Energy, LLP, GBC Metals, LLC, Illinois Cement Company, Linde NA, Inc., Olin Corporation, Tate & Lyle Ingredients America, Inc., United States Steel Corporation - Granite City Works, Viscofan U.S.A., Inc., Washington Mills Hennepin, Inc., and the University of Illinois, participated in this case. They refer to themselves collectively as the Illinois Industrial Energy Consumers ("IIEC" or "IIEC Companies"). Pursuant to Section 200.800 (83 Ill. Adm. Code Part 200.800) of the Rules of Practice of the Illinois Commerce Commission ("ICC" or "Commission"), and the briefing schedule set by the Administrative Law Judges, the IIEC Companies named above present their Initial Brief in this docket for the Commission's consideration.[1]

I. INTRODUCTION

A. Overview

These consolidated proceedings were initiated by 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") (collectively "Ameren", "Ameren Companies" or "AIU"). The Ameren Companies filed for modification of certain rates and tariffs for their gas and electric service and a general increase in their natural gas

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[1] This brief follows the specified outline for the briefs in this proceeding. It places those captions relevant to the issues addressed by IIEC in bold in the index. IIEC has inserted some additional subcaptions under the outline captions to better organize this brief.

(“gas”) and electric delivery service rates. In their original electric delivery service rate filing, the Ameren Companies proposed the following revenue (percentage) increases: AmerenCILCO $27.8 million (22.8%); AmerenCIPS $50.6 million; (21.5%); and AmerenIP $102.3 million (22.1%). (Nelson, Ameren Ex. 1.0E at 5:100-105).[2] The Ameren Companies also proposed increases in their gas revenue requirements: AmerenCILCO $8.8 million (11.8%); AmerenCIPS $11.4 million (15.6%); and AmerenIP $24.9 million (14.6%). (*Id*. at 5:107-111).

Four IIEC witnesses presented testimony in this proceeding, addressing elements of the electric and gas revenue requirements for the Ameren Companies, Ameren’s electric embedded cost of service studies ("COSS"), revenue allocation issues, and other rate design issues. Specifically, IIEC offered the testimony of the following witnesses: Mr. Robert R. Stephens (Stephens Direct, IIEC Ex. 1.0-C and Rebuttal, IIEC Ex. 5.0-C); Mr. Michael Gorman (Gorman Direct, IIEC Ex. 2.0-C and Rebuttal, IIEC Ex. 6.0-C); Mr. Greg R. Meyer (Meyer Direct, IIEC Ex. 3.0 and Rebuttal, IIEC Ex. 7.0); and Mr. David L. Stowe (Stowe Direct, IIEC Ex. 4.0 and Rebuttal, IIEC Ex. 8.0-C), along with the exhibits accompanying their respective testimonies.

Mr. Gorman recommended a fair return on common equity of 10.0% for the Ameren Companies for both electric and gas operations. Mr. Gorman also testified that the Ameren Companies failed to properly reflect post test year changes in the Ameren Companies’ rate bases. They increased rate base for planned post-test year plant additions but failed to recognize the

[2] Citations to testimony and exhibits in this case will take the following form: witness name, party, exhibit number, page number(s):line number(s). For example, Stephens, IIEC Ex. 1.0-C at 1:1-2. Transcript citations will include the witness name, date of transcript and page number(s). For example, Stephens, June 9, Tr. 100).

depreciation of (decreases to) rate base taking place at the same time. He explains the necessary adjustment to properly reflect post-test year changes in rate base. Mr. Gorman's recommended adjustment would reduce the gas revenue requirement for AmerenCILCO by $600,000, AmerenCIPS by $654,000, and AmerenIP by $5.119 million. It would reduce the electric revenue requirement for AmerenCILCO by $3.051 million; AmerenCIPS by $6.922 million and AmerenIP by $10.006 million. (Gorman, IIEC Ex. 2.0-C at 4:Table 1).

Mr. Meyer testified on several revenue requirement issues. Specifically, he addressed the Company's cash working capital balance, injuries and damages expense, amortization of AmerenIP merger expense, and uncollectible expense. Adoption of Mr. Meyer's recommendations on cash working capital would reduce the electric revenue requirement for AmerenCILCO by $246,505, for AmerenCIPS by $446,131, and for AmerenIP by $904,651. It would reduce the gas revenue requirements for AmerenCILCO by $797,553, for AmerenCIPS by $556,583 and AmerenIP by $1,434,396. (Meyer, IIEC Ex. 3.1 at 1-2).

Adoption of Mr. Meyer's recommendations on injuries and damages expense would decrease the electric revenue requirements by $60,887 for AmerenCILCO, $237,168 for AmerenCIPS and $374,632 for AmerenIP. (Meyer, IIEC Ex. 3.3). Ameren's gas revenue requirements would decrease by $23,097 for AmerenCILCO, $19,326 for AmerenCIPS and $86,688 for AmerenIP. (Meyer, IIEC Ex. 3.3 at 1-2).

Adoption of Mr. Meyer's recommendations on uncollectible expense decreases electric revenue requirements by $285,000 for AmerenCILCO, $603,000 for AmerenCIPS and $1,028,000 for AmerenIP. Gas revenue requirements would increase by $21,000 for AmerenCILCO and $10,000 for AmerenIP and would decrease by $7,000 for AmerenCIPS. (Meyer, IIEC Ex. 3.5).

Mr. Stephens addressed the impact of the Ameren Companies' proposed electric delivery service rate increases on industrial customers; Ameren's reallocation of the tax imposed under the Public Utilities Revenue Act (the "PURA Tax"); certain electric cost of service issues; class revenue allocation and rate design issues, including rate moderation, and tariff provisions that discourage the development of combined heat and power projects. He also recommended adjustments to the Ameren Companies electric operating expense to reflect refunds of past PURA Tax, which amounted to $2,685,589 for AmerenIP, $637,956 for AmerenCIPS, and $649,195 for AmerenCILCO. (Stephens, IIEC Ex. 5.0-C at 17-18:332-368).

IIEC witness Stowe addressed the electric embedded cost of service ("ECOS") studies presented by Ameren. Mr. Stowe proposed certain improvements to those studies that should be adopted it the Commission uses those studies for any purpose. He also modeled changes to the ECOS studies based on IIEC witness Stephens' proposals for collection and allocation of the PURA Tax. Finally, Mr. Stowe addressed Ameren's development of its non-coincident peak ("NCP") demand allocation factors.

IIEC Companies in this proceeding are large consumers of electricity, mostly large manufacturing companies of some kind. (Stephens, IIEC Ex. 1.0-C at 16:356-357). Ameren proposes unprecedented delivery service rate increases for its largest customers (and the largest employers in its service territory), at a time when Illinois ranks fourth among the States in loss of manufacturing jobs. Illinois lost 83,500 manufacturing jobs in the 12 months ending July 2009. (Stephens, IIEC Ex. 1.0-C at 16:350-356). The unprecedented increases to the delivery service rates for these customers in the Ameren service territories can only exacerbate this problem.

In some instances, the increase to delivery service charges is in excess of 1000% and for some customers this translates to actual increases in excess of $1 million per year. (Stephens, IIEC Ex. 1.0-C at 3:44-46; *See*, e.g., L. Jones, Ameren Ex. 40.2 at 6). In seeking increases of this magnitude, Ameren claims to have considered rate moderation and rate impact principles. However, Ameren has been so selective in the application of these principles that the rate increases to the Rate DS-4 class for each Ameren Company are more than two times the next highest increase for any other rate class. (Stephens, IIEC Ex. 1.0-C at 6:132-133). After application of Ameren's rate moderation approach, the overall DS-4 class actually faces increases of 60.1% in AmerenIP, 57.6% in AmerenCIPS and 57.3% in AmerenCILCO. This compares to increases for the DS-3 class of 29.4% for AmerenIP, 20.5% for AmerenCIPS and 24.5% for AmerenCILCO. (Stephens, IIEC Ex. 1.0-C at 5:Table 1).

Class increases of approximately 60% are the highest or among the highest increases ever proposed for the DS-4 class in the history of Ameren's delivery service rate cases. (Stephens, IIEC Ex. 1.0-C at 6:138-140). Certainly, delivery services of this magnitude justify appropriate rate moderation and mitigation.

Ironically, Ameren proposes an extension of a rate limiter that limits the delivery service rate increase of a subgroup of DS-3 and DS-4 customers, known as the Grain Drying Customers, who face increases of 20-42% without the limiter. (*See*, L. Jones, Ameren 2d Rev. Ex. 16.0E at 35:726-728; and Adkisson, GFA Ex. 1.0E at 3:48-49). It is worth noting that the rate limiter is applied on top of Ameren's rate moderation.

Indeed, if moderated rate increases of 20% to 42% for certain subclasses of DS-3 and DS-4 customers justify additional rate mitigation, such as the rate limiter, then mitigated increases in the neighborhood of 60% would most certainly justify additional rate moderation or even a different rate moderation approach.

The DS-4 class increases of approximately 60% are dire enough; but Ameren goes a step further in proposing even larger increases for certain DS-4 subclasses. Ameren actually increases the rates for the DS-4 High Voltage subclass by 78% in AmerenIP, 131% in AmerenCIPS and 135% in AmerenCILCO. For the DS-4 100 kV and above subclass, delivery service rates would increase by 760% for AmerenIP, 1270% for AmerenCIPS and 541% for AmerenCILCO. (Stephens, IIEC Ex. 1.0-C at 7:Table 2). Ameren's purportedly moderated/mitigated increases for the DS-4 100kV and above subclasses produce rate impacts for those subclasses that are approximately 5.5 times to 20 times greater than the highest increase proposed for the DS-4 class. Furthermore, these increases are 13 to 30 times higher than the 42% increase for some customers in the subgroup of seasonal customers (grain drying customers) used to justify the additional rate mitigation associated with the rate limiter.

Amazingly, the increase to the DS-4 class would be even higher but for Ameren's proposal to limit the rate increase to any rate class (but not subclass) to 125% of the system average increase, but without consideration of the PURA Tax. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 7:116-118). A rate moderation plan that produces rate increases that are higher than any Ameren Company delivery service rate increase in history, and subclass increases ranging from 541% to 1270%, have no credibility from a customer point of view and should, on their face, be considered unreasonable by the Commission.

Ameren has given virtually no serious consideration to limiting or moderating the level of increase on its largest customers. As will be discussed further in Section VII of this brief, Ameren's sole concern seems to have been in controlling the level of increase faced by small customers, and camouflaging the level of delivery service increase imposed on large customers. Accordingly, it has taken extraordinary steps to try to shift rate responsibility to larger customers, in order to make the required increase more politically palatable.

Ameren witnesses have argued that the increases are only a small percentage of the DS-4 customers' total cost for electricity, i.e., delivery service cost plus commodity cost. IIEC will explain why only delivery service costs are relevant to delivery service rate setting. A customer's other costs, like electric commodity costs, have no bearing on the reasonableness of delivery service rates. In the real world, under the Ameren approach to rate mitigation and moderation, in at least one instance, a DS-4 customer will see a delivery service bill increase from $250,000 per year to in excess of $2 million per year. (Stephens, IIEC Ex. 1.0-C at 12, Fn. 8). Thus, the actual dollar impact associated with Ameren's proposals is real and significant.

Indeed, Ameren revenue requirement witnesses have made clear that when it comes to

Ameren's own cost recoveries, revenue requirements and business operations, increases in individual expense items as small as only 3% are significant to Ameren. (Nelson, Dec. 14, Tr. 56). Ameren stressed the importance of recovery of these increased expenses, even if they constituted only a small fraction of Ameren's total operating expense. (Nelson, Dec. 14, Tr. 54). Ameren has conceded that its manufacturing customers might have a significant concern if Ameren proposed to increase their delivery service rates by 1000%. (Nelson, Dec. 14, Tr. 58). Unfortunately, Ameren's proposals do increase large manufacturers' rates by as much as 1000% and more, but Ameren has elected not to initiate any realistic moderation or mitigation of those increases.

The rate impacts described above are also a function of Ameren's proposal to change the allocation of the PURA Tax from its historic plant in-service allocator to an energy-only allocation. (Stephens, IIEC Ex. 1.0-C at 7-8:166-172). These rate impacts are also driven by errors and mistakes in the allocation of distribution plant investment to large customers (i.e., customers 100 kV and above) as well as the mis-allocation or lack of allocation of distribution plant costs to other customer groups. (Stephens, IIEC Ex. 1.0-C at 7-8:167-169). While IIEC supports the concept of cost-based rates, it assumes in doing so that utilities present a valid cost of service study, accurately measuring the cost of service of customers and customer classes. In this case, a review of the entire record has disclosed that the Ameren cost of service studies do not accurately measure the cost of serving customer classes. Unfortunately, while IIEC's modifications to the ECOS studies correct some of the more egregious errors, has become evident in the later stages of the case that the underlying studies do not provide good foundations for rate development. This renders suspect not only Ameren's ECOS studies, but all modified studies based thereon. The Commission is without a solid basis to make appropriate revenue allocations to the customer classes.

In the circumstances described, IIEC has proposed to first make appropriate reductions to Ameren's revenue requests. Second, IIEC addressed the known deficiencies in Ameren's ECOS studies. Third, IIEC proposed a proper allocation of the PURA Tax, including an alternative or compromise approach. Fourth, IIEC recommends the Ameren ECOS studies not be used for revenue allocation purposes and rates be increased on an across-the-board basis. Fifth, if the Commission, despite IIEC's objections and supporting evidence, elects to use the Ameren ECOS studies for revenue allocation and rate design in this case, IIEC recommends correction of certain errors. Sixth, if the Commission does not approve an across-the-board increase, IIEC has proposed an appropriate rate moderation plan, which will provide for gradualism and avoid rate shock for all customer classes and subclasses, and is not contingent on the Commission's findings on any revenue requirement cost of service or revenue allocation issues. IIEC discusses these matters below.

F. Other Legal Issues

As the Commission considers the myriad issues in this proceeding, it must apply a series of governing legal standards. Some, like the burden of proof that Ameren must meet as to the justness and reasonableness of its proposed rates, charges, and practices (in whole and in part), are broadly applicable. Others are more focused in their relevance. IIEC will address legal issues that are particularly relevant to a specific issue in the context of its argument on that issue.

II. RATE BASE

A. Overview

In this section of its brief, IIEC addresses two elements of the Ameren Companies (gas and electric) proposed rate bases. First, IIEC proposes modification of Ameren's pro forma plant additions to the test year rate bases so that all the known and measurable changes to the two main components of those rate bases are accurately measured during the post-test year period, and so that the rate bases and associated revenue requirements are not overstated. Second, IIEC addresses the appropriate level of the cash working capital requirement for all the Ameren Companies.

B. Resolved Issues

2. Historical Plant Additions (2002-2006)

IIEC did not challenge the amounts of Ameren's historical pre-test year plant additions. This is not a test year rate base issue. The only apparent purpose of this information is to serve as an element of Ameren's argument for its proposal to increase test year rate base to recognize planned post-test year plant additions without recognizing contemporaneous decreases to rate base. IIEC will address issues concerning these non-test year investments in that context.

C. Contested Issues

1. Pro Forma Plant Additions (2009-2010)

2. Accumulated Reserve for Depreciation

IIEC does not consider Ameren'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. The Commission is permitted to include in Ameren's ratemaking rate bases only Ameren's plant in service (net plant), which cannot be determined by looking at only one component of that calculated investment amount. The proposed *pro forma* adjustments for these post-test year plant additions, though listed separately in the brief outline, will be addressed together in this section of IIEC's brief.

a. Introduction

In his direct testimony, IIEC expert witness Michael Gorman responded to Ameren's significant overstatement of its proposed rate base and resulting cost of capital. (Gorman, IIEC Ex. 2.0-C at 80:1699, 82:1747). The overstatement was the result of Ameren's selective *pro forma* adjustment to reflect post-test year changes in rate base. (*Id.* at 8-0:1700-1713). The Ameren Companies proposed 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 Ameren. (Stafford, Ameren Rev. Ex. 2.0E at 22:463-466). Altogether, Ameren proposes to add about a quarter-billion dollars in plant investment to its ratemaking rate base. (Ebrey, Dec 17, Tr. 800). Ameren'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. (*Id.* at 742-745). Although Ameren suggests that its proposed changes to recognize plant retirements and retirement-related depreciation also affected its additions to rate base, 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. (Stafford, Ameren Rev. Ex. 2.0E at 22:474-479; Gorman, IIEC Ex. 2.0-C at 80:1708).

Mr. Gorman's testimony explained that rate base can increase or decrease over time, depending mostly on the change to "net" utility plant investment. 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. (*Id.* at 81:1728-1735). 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. Because Ameren accounted almost exclusively for the plant addition increases to gross utility plant while ignoring the contemporaneous offset of changes in accumulated depreciation, Ameren overstated both its net plant and the rate base on which it is authorized to earn a return. (*Id.* at 82:1743-1748).

Mr. Gorman's testimony provided detailed support for his conclusions about (a) the inconsistency of Ameren's proposal with accepted accounting practice, which received unanimous validation from experts in the case, (b) the effect of Ameren's proposed unbalanced adjustment, based on an unchallenged analysis of the results of an actual instance of such an adjustment and echoed by other experts in the case, and (c) the adjustment required to properly reflect post-test year changes in the plant investment Ameren uses to provide service to customers. While Mr. Gorman did not contest the amount of Ameren's plant additions, IIEC does oppose Ameren's proposed unbalanced adjustment, because it overstates the Ameren Companies' rate bases and the cost of equity. IIEC has proposed, in the testimony of Mr. Gorman, an appropriate correcting adjustment, which is easily modified to match whatever period of plant additions the Commission may approve.

Staff questioned whether the planned plant additions were, in fact, known and measurable changes that are reasonably certain to occur, as required by the Commission's *pro forma* adjustment rule (83 Ill. Adm. Code 287.40). Ultimately, Staff accepted the Ameren Companies' evidence on this point as to planned plant additions through February 2010. Ameren modified its proposal to encompass only that shortened period. Staff and Ameren also resolved the amounts properly attributed to the accepted plant additions. (Fiorella, Ameren Ex. 69.0 at 4:68-74; Ebery, Dec 17, Tr. 800). However, at no point in its filed testimony did Staff present any analysis or considered opinion on the lawfulness or appropriateness of Ameren's proposed *pro forma* adjustment to recognize the planned largest post-test year increases to rate base while ignoring the largest contemporaneous post-test year deductions from rate base, which are required by law. (Ebrey, Dec 17, Tr. 803).

Ameren emphasizes that its proposed adjustment was constructed to mimic the adjustments accepted in the Commission's decisions in the ComEd and PGL cases. (Fiorella, Ameren Ex. 69.0 at 4:74-79). Both cases are now the subject of appellate judicial review. Ameren has offered no other substantive support for its proposed rate base adjustment that can stand on its own. Ameren depends <u>entirely</u> on transferring the result of those decisions to a determination on this record. The reasons those decisions cannot be applied fall into two categories. The first group consists of legal requirements -- both statutory and regulatory -- that bar the result Ameren seeks. The second group comprises matters of fact established by the evidence in this record, on which the Commission must base its decision. Ameren's proposed adjustment is not supported by the manifest weight of that evidence. The pertinent prohibitive requirements are discussed in the following sub-sections of IIEC's brief.

b. Ameren's Proposal Is Unlawful

i. Prior Commission Decisions Are Not Determinative Or A Bar to IIEC's Evidence and Arguments

As IIEC noted earlier, Ameren, in proposing this *pro forma* adjustment, has relied for substantive support almost entirely on the Commission's decisions in certain Commonwealth Edison and Peoples Gas cases. (Stafford, Ameren 2d Rev. Ex. 51.0 at 21:486; Fiorella, Ameren Ex. 69.0 at 4:74-79 (*citing* Re Commonwealth Edison Co., Dkt 07-0566, Order, Sept. 10, 2008 ("ComEd Decision"), Re North Shore Gas Co,. Dkt 07-0241/07-0242 (cons.), Order, Feb. 5, 2008 (North Shore Decision") and earlier Commonwealth Edison decisions).

IIEC notes first that the two most recent ComEd decisions on which Ameren relies as support for its proposed *pro forma* adjustment are both the subject of appellate judicial review. (*See*, Commonwealth Edison Company, et al., v. Illinois Commerce Commission, et al., Gen. No. 2-08-0959, et al., (Cons.) (2d Dist. Illinois) and Gen. No. 2-06-1284, et al., (Cons.) (2d Dist. Illinois)). Even though Commission orders become and remain effective unless and until they are stayed or reversed (220 ILCS 5/10-204), the effect of those prior decisions in this case is not significant. First, prior Commission decisions are not *res judicata*. (Mississippi River Fuel Corp. v. Illinois Commerce Com.,1 Ill. 2d 509, 513 (1953)). The record in this proceeding is the exclusive lawful basis of a decision in this case. (220 ILCS 5/10-103). As detailed later in this brief, the record in this proceeding is clearly and substantively distinguishable from the record of any of the cited cases.

Second, Salvatore Fiorella, the Ameren witness, who testified about the past Commission decisions on this issue that Ameren cites and relies on, agreed that the Commission must seriously consider all arguments and evidence of record -- even if the Commission has previously rejected the argument on a different record. Mr. Fiorella further agreed that arguments previously presented can even be the basis for a reversal of a prior Commission position on a new record. (Fiorella, Dec 15, Tr. 361-363).

That testimony is merely consistent with the legal mandates that require the Commission to decide each case on the record before it, irrespective of prior decisions on an issue. It is constrained in that endeavor only by its duty to explain departures from established past policies, with its reasoning articulated in its decision. (*See* 220 ILCS 5/10-103; 220 ILCS 5/10-201(e)(iv)A; Mississippi River Fuel Corp. v. Illinois Commerce Com.,1 Ill. 2d 509 at 513). Thus, the prior Commission decisions cited by the Ameren Companies are not a bar to a review of the evidence and arguments that is not compromised by earlier determinations. Indeed, the law requires precisely that approach. The triers of fact must reject suggestions that this issue has been settled and is beyond re-examination.

ii. Ameren's Proposed Pro Forma Adjustment Violates the PUA

The PUA expressly limits the ICC's authority with respect to what the ICC may properly include in a utility's ratemaking rate base. As limited by Section 9-211 of the Public Utilities Act

(220 ILCS 5/1-101 *et seq.* (“PUA” or the “Act”), a utility‘s 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.” (220 ILCS 5/9-211). 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. (Gorman, IIEC Ex. 2.0-C at 87:1880-1882; ComEd Decision, Dissent at 2-3). Ameren asks the Commission to ignore one-half of that rate base calculation by approving its unbalanced *pro forma* adjustment.

Certain matters critical to an accurate determination of ComEd’s lawful rate base are not in dispute. Those undisputed accounting rules and conventions establish clear violations of law. First, as IIEC, Ameren, and Staff agreed, the standard calculation of a utility’s rate base for ratemaking purposes is undisputed, and it is based on a calculation of net plant, not gross plant. (*See, e.g.*, Gorman, IIEC Ex. 2.0-C at 84:1799; Stafford, Dec. 15, Tr. 323-327; Ebrey, Dec 17, Tr. 739-741). An accurate determination of the lawful rate base requires including the accumulated depreciation reserve in the calculation -- as Ameren witness Ronald Stafford testified:

> Q. Do you agree that if we tried to calculate a utility's rate base without taking into account accumulated depreciation, that calculation would overstate the rate base?
>
> A. I certainly agree. In fact, depreciation reserve is a big, very material credit in the calculation of the AIU's rate base.
> (Stafford, Dec. 15, Tr. 327).

Staff’s expert Ms Ebrey confirmed that a failure to take account of a utility’s accumulated depreciation in determining net plant (and rate base) at any point in time will produce an overstatement.

In accordance with Commission's accounting rules, Ameren recognizes the decline (over time) in the value of its plant used to provide service through depreciation. Depreciation expense is recorded monthly, using Commission-approved depreciation rates and book values kept in accordance with Commission accounting rules. The cumulative declines in value are recorded in the accumulated depreciation reserve. (Ebery, Dec 17, Tr. 742-744).

Ameren's proposed adjustment -- which would calculate Ameren'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. Ameren's proposed adjustment asks the Commission to violate the PUA'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.

Second, no party disputes that an excessive rate base also would result in a revenue requirement that exceeded the utility's cost of capital. (Gorman, IIEC Ex. 2.0-C at 90:1932-1938; Stafford, Dec 15, Tr. 327-329; Ebrey, Dec 17, Tr. 741). Rates set on such an excessive basis would not be just and reasonable and cannot lawfully be approved by the Commission. (220 ILCS 5/9-101).

ii. Ameren's Pro Forma Adjustment Is Not Consistent With the Commission's Test Year and Accounting Rules or Governing Test Year Case Law

Ameren's proposed adjustment is inconsistent with the requirements of the Commission's accounting and *pro forma* adjustment rules and with the test year principles defined by the Illinois Supreme Court. (*See* 83 Ill. Adm Code 287.40, Part 287, Part 285, Part 415, Part 505; Business & Professional People for Public Interest v. Illinois Commerce Comm., 136 Ill. 2d 192 (1989) ("BPI I"); Business & Professional People for Public Interest v. Illinois Commerce Comm., 146 Ill. 2d 175 (1991) ("BPI II")).

The unbalanced adjustment proposed by Ameren must be rejected for at least three reasons under test year principles defined in *BPI I* and *BPI II*. First, the adjustment is inconsistent with any reasonable reading of Section 287.40, the ICC's test year pro forma adjustment rule, and with standard regulatory accounting conventions. (*See* 83 Ill. Adm. Code 287.40; Ebrey Dec 17, Tr. 746). Second, neither Ameren nor the prior Commission decisions on which Ameren relies provide any authority for the Commission's departure from standard regulatory accounting and test year principles, as defined by the Illinois Supreme Court. Third, 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. (*See* Re Central Illinois Public Service Company (AmerenCIPS) *et al*., ICC Dkts. 02-0798,03-0008, 03-0009 (cons.), Order, October 22, 2003 ("Ameren Cases Decision")).

Ameren proposed a 2008 historical test year for setting rates in this case. Under the Commission's test year rules, utility costs and revenues are matched over that consistent time period, the test year. (*See* 83 Ill. Adm. Code 287.20, 287.40; *BPI I*, 136 Ill. 2d 192 at 225-226). Data from outside that test year can be considered in setting rates only on the specific conditions defined in the

ICC's rules, including Section 287.40 (Pro Forma Adjustments), which governs the use of post-test year data. That section contemplates balanced adjustments for "all known and measurable changes" affecting ratepayers, in the components of Ameren's revenue requirement. Ameren'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. Ameren proposes smaller offsets that avoid including one of the two principal components of a proper calculation of rate base investment value. (Gorman, IIEC Ex. 2.0-C at 80:1708-1713). Under the Commission's accounting rules, there will be "changes affecting the ratepayers in plant investment," attributable to increases in accumulated depreciation, that will, in fact, be recorded in Ameren's reserve for accumulated depreciation over the period of the post-test year plant additions. (Stafford, Dec 15, Tr. 330-33; Ebrey, Dec 17, Tr. 742-743). Thus, those changes are known and measurable, and certain to occur. A selective departure from standard accounting to allow the unbalanced, inaccurate calculation of plant investment Ameren proposes is inconsistent with Section 287.40.

As explained by several witnesses on this record, unless accounting and ratemaking norms are abandoned, the phrase "changes affecting ratepayers in plant investment" must refer to changes in the net plant in rate base, since that is the basis for setting rates and ratepayers are not affected dollar-for-dollar by gross plant investment amounts. (Gorman, IIEC Ex. 2.0-C at 81-82:1736-1740). Net plant is the amount used in determining the capital costs included in customer rates. (Stafford, Dec 15, Tr. 326- 328). Staff accounting expert Ebrey confirmed that the calculation Ameren proposes to use for its unbalanced adjustment to recognize known and measurable post-test year changes in plant investment would be anomalous. (Ebrey, Dec 17, Tr. 746).

The Illinois Supreme Court has explained the purpose of test year rules as "to prevent a utility from overstating its revenue requirement by mismatching low revenue data from one year with high expense data from a different year." (*BPI II*, 146 Ill. 2d 175 at 238). The Commission has elaborated, explaining that the purpose of the matching requirement is "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." (Ameren Cases Decision at 11).

Though the decision is directly on point and involves the very utilities before the Commission in this case, its principal recommendation is the quality of its analysis. In the *Ameren Cases Decision*, the ICC examined the application of test year requirements to adjustments for post-test year plant additions and accumulated depreciation in a variety of circumstances. That comprehensive analysis is the only one the Commission has performed in any decision. The touchstone of that analysis is "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." (*Ameren Cases Decision*, at 10). The unbalanced calculation of plant investment and rate base proposed by Ameren is not representative of the period rates set in this case will be in effect. In fact, the proposed mismatch of February 2010 plant additions and December 2008 accumulated depreciation is one that will <u>never</u> exist on the books of the Ameren Companies. (Ebrey, Dec 17, Tr. 746). The adjustment proposed by Mr. Gorman is necessary for accurate measurement of the utility's rate base, and not just its plant additions. Ameren'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.

Ameren witness Mr Fiorella attempted to diminish the importance of that Commission decision on this issue, though Ameren followed it analysis in its most recent case. (Gorman, IIEC Ex. 2.0-C at 84:1800-1802; Fiorella, Ameren Ex. 69.0 at 14:297 ("The Docket No. 02-0798 Order is of no consequence in this proceeding."). He points to the *ComEd Decision*, where the Commission misread the *Ameren Cases Decision* requirement to mean where net plant in service is increasing, post-Test Year plant additions must be allowed. (ComEd Decision at 22-29). The *Ameren Cases Decision* in fact required that "if a utility demonstrated significant post test year capital additions that were not largely or entirely off-set by increases in accumulated depreciation, the Commission *might be inclined* to allow post test year capital additions to rate base." (Ameren Cases at 10). One utility in those cases met the stated conditions. Its plant additions were not automatically allowed. The Commission held that for that utility "additions to plant in service should be included in rate base *to the extent that they exceed increased accumulated depreciation*." (*Id*. at 10-11).

Moreover, under that the misinterpretation of the decision that Ameren relies on, the determination of allowable test year costs is determined -- unlawfully -- by rate base data from outside the test year and outside the governing *pro forma* adjustment rule. (83 Ill. Adm. Code 287.20, 287.40). In any case, the Commission cannot lawfully decline to perform the assessment of test year evidence that is mandated by the PUA's requirement for record-based decisions. (220 ILCS 5/10-103). And the Commission cannot abandon its test year rules so that allowable Test Year costs hinge on data from outside the Test Year that does not meet the requirements of Section 287.40. (83 Ill. Adm. Code 287.40).

iii. *The Evidence In This Record Requires A Different Result From Prior Cases*

The ComEd decisions and the North Shore decision are overwhelmed by facts of record that distinguish this case and leave those decisions without effect. In prior cases the Commission was presented with competing views of the future and the effects of its approvals. In this case the Commission has hard evidence of the consequences of approval of such unbalanced *pro forma* adjustments. In addition, there is ample expert testimony in this case from a broad range of experts (including the utilities' own) showing the inconsistency of such adjustments with the Commission's accounting rules and conventions.

IIEC's Mr. Gorman presented the most compelling evidence of the consequences of *pro forma* adjustments like Ameren's proposal. He examined the real world results of the Commission's approval of ComEd's similar adjustment in that utility's most recent rate case (ComEd Decision at 27-30; Gorman, IIEC Ex. 2.0-C at 87-90:1896-1941, including Table 7). Mr. Gorman's analysis was not rebutted -- in fact, not even <u>challenged</u> -- by the testimony or exhibits of a single witness. This unchallenged evidence of the effect of *pro forma* adjustments like Ameren's proposal shows beyond reasonable dispute that the effect would be an unlawful expansion of Ameren's rate base beyond the Commission's lawful authority.

In the *ComEd Decision* case, Mr. Gorman testified that ComEd's adjustment would overstate net plant and rate base, and would artificially boost the cost of capital in its revenue requirement. (Gorman, IIEC Ex. 2.0-C at 88:1901-1902). The Commission nonetheless permitted ComEd's rates to be set based on ComEd's post-test year plant addition adjustments. In this record, Mr. Gorman assessed the accuracy of ComEd's measurement of net utility plant (and rate base) during the period the ordered rates have been in effect. Using data from subsequent regulatory filings, Mr. Gorman presented the results in Table 7 of his direct testimony. His analysis shows that ComEd's projected increase in gross plant in service (plant additions) was reasonably accurate. However, 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. As a result, 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. Mr. Gorman concluded that actual experience confirms the results predicted by an unbiased application of the Commission's accounting and test year rules. Specifically, 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. (*Id.* at 90:1932-1935).

Mr. Gorman testified that because Ameren did not properly offset plant additions with the contemporaneous buildup of the accumulated depreciation reserve, that its adjustment to rate base is in conflict with the Commission's test year rules. Specifically, the adjustment does not properly reflect changes affecting plant investment used to provide service, resulting in an overstated net utility plant and rate base. (Gorman, IIEC Ex. 2.0-C at 86:1853-1864). Ameren will also overstate its cost of capital because it has overstated its rate base. (*Id.* at 86:1865-1869; Ebrey, Dec 17, Tr. 740-742; Stafford, Dec 15, Tr. 327-329).

In addition, this record contains extensive expert testimony explaining that Ameren's proposal is inconsistent with Commission accounting and depreciation rules and is not representative of the rate base that Ameren will have in place when rates are in effect. This evidence was discussed above in the course of IIEC's legal argument and will not be repeated here. There is also broad agreement that unreasonable costs (including, presumably, unlawful costs) cannot be the basis for just and reasonable rates. (Stafford, Dec 15, Tr. 319-320; Ebrey, Dec 17, Tr. 738). Accordingly, the unlawful and ill-advised *pro forma* adjustment proposal from Ameren must be rejected.

5. Cash Working Capital

Cash working capital ("CWC") is included as part of AmerenCILCO's, AmerenCIPS' and AmerenIP's rate base for ratemaking purposes. (Heintz, Ameren Ex. 4.0E at 5:95-96). CWC is the amount of funds required to finance the day-to-day operations of Ameren and represents the amount of cash it needs to keep on hand to meet their cash operating needs. (*Id.* at 3:55-57). Ameren has calculated its CWC requirements using the Gross Lag Methodology. (*Id.* at 4:65-68).

The analysis of the differences between the revenue lags and expense leads is referred to as a lead-lag study. (*Id.* at 5:97-99). Lead-lag studies are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to Ameren. (*Id.* at 5:99-101). The lag time is offset by a lead time during which Ameren receives goods and services, but pays for them at a later date. (*Id.* at 5:101-103). The "lead" and "lag" are measured in days. (*Id.*).

Next, the dollar-weighted lead and lag days are divided by 365 to determine a daily CWC factor. (*Id.* at 5:103-106). Ameren then multiplies the CWC factor by the annual test year cash expenses to determine the amount of CWC required for operations. (*Id.*). This final calculation determines the amount of CWC included as part of Ameren's rate base. (*Id.* at 5:106-107).

AmerenCILCO's requested level of rate base includes $6,346,000 of CWC requirements for the gas business and $535,000 for the electric business. (Heintz, Ameren Ex. 4.0E at 23:483-484). AmerenCIPS' requested level of rate base includes $4,055,000 of CWC requirements for the gas business and $2,242,000 for the electric business. (*Id*. At 25:485-486). AmerenIP's requested level of rate base includes $10,571,000 of CWC requirements for the gas business and negative $1,083,000 for the electric business. (*Id.* at 23:483-488)

Ameren has proposed five lags, which comprise the total revenue lag: Usage Service Lag; Billing Lag; Collection Lag; Payment Processing Lag; and Bank Float Lag. (IIEC, Meyer Ex. 3.0 at 4:54-70). Based on weighted average data from Ameren's Customer Service System and by considering accounts receivables balances by class of customer by days aged, the average collection lag was determined to be 28.13 days for both the gas and electric businesses. (Ameren, Heintz Ex. 4.0E at 8-9: 172-175). The longer the collection lag the higher the CWC requirement.

Ameren's use of a 28.13 day collection lag is overstated and unreasonable for three reasons. First, a 28.13 day collection lag suggests that on average every customer of Ameren, with exception of the Non-Residential Special Customer Type, pay their bills beyond the due date and late payment grace period. (*Id.* at 6:106-108). Second, the data used by Ameren to develop its collection lag contains uncollectibles, and uncollectibles expenses are included as a component of Ameren's cost of service. Third, the collection lag period is inconsistent with Commission rules. (IIEC, Meyer 3.0 at 4-5:74-85). However, uncollectible expense is already recovered through the charges to customers who do pay their bills. (IIEC, Meyer Ex. 7.0 at 6:122-124). For these reasons, explained in detail below, IIEC witness Greg Meyer recommends a collection lag of 21 days.

i. *A 28.13 day collection lag suggests all customers except certain Non-Residential Customers, pay after the due date and grace period.*

A 28.13 day collection lag suggests that, on average, every customer of Ameren, with the exception of the Non-Residential Special Customer Type, pay their bills beyond the due date and late payment grace period. (*Id.* at 6:106-108). To put another way, on average, every customer (except Non-Residential Special Customer Type) should be assessed a late payment fee. (*Id.* at 6:108-110).

As stated previously, the 21-day collection lag IIEC recommends matches the collection period for the residential class and is longer than the collection periods for the commercial and industrial customers. Undoubtedly many customers pay their bills sooner than the last allowable day. (*Id.* at 6:115-117). IIEC believes that use of a 21-day collection lag is conservative.

Ameren argues the IIEC should have provided recommendations on how a 21-day collection lag could be achieved. (Ameren, Heintz Ex. 53.0 at 7:146-153). Ameren is proposing a collection lag that is over seven days longer (28.13 v. 21) than the period within which residential customers are required to pay their bills specified in the Commission's rules. (83 Ill. Adm. Code 280.90). Ameren's "real world" argument does not provide substantive evidence for increasing the collection lag above and beyond the payment period defined by Commission rule. (Ameren, Heintz Ex. 53.0 at 7:149-150).

Ameren's attempt to shift the responsibility of demonstrating the reasonableness of its proposal is defeated by the express burden of proof requirements of the PUA. (220 ILCS 5/9-201(c)). IIEC has no responsibility to prove the reasonableness of the Commission's collection rules. Rather, Ameren must prove the reasonableness of their proposed collection period. Ameren has not justified its proposed 28.13 day collection lag as reasonable. Therefore, Ameren's collection lag proposal should be rejected.

ii. Ameren's collection lag is calculated erroneously because the data includes uncollectible expense, which is already included as a component of Ameren's cost of service, and inflates the estimated collection lag.

The data used by Ameren to develop its collection lag of 28.13 days contains billed revenues and accounts receivables for Ameren customers who will never pay their bill. (IIEC, Meyer Ex. 7.0 at 6:120-121). These dollars represent uncollectibles, which are included separately as a component of Ameren's cost of service, and recovered through charges to customers who do pay their bills. (*Id.* at 6:122-124).

Including the uncollectibles is an error in Ameren's collection lag calculation. Removing the uncollectibles costs would decrease the collection lag calculated by Ameren. (*Id.* at 6:126-128). Further, including uncollectibles in the accounts receivables used for Ameren's study improperly increases the receivable balance used to develop the weighted lag periods, those dollars will never be reduced by customer payments. (*Id.* at 6:128-130). Reducing both the billed revenues used to weight Ameren'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 Ameren.

Ameren witness Heintz agrees that uncollectibles should not be a part of the lead-lag study. (Heintz, Dec. 15, Tr. 240). However, in response to IIEC Data Request No. 8.01, Ameren confirms that uncollectibles were not removed from their collection lag calculation. (Meyer, IIEC Ex. 7.0. at 6:124-126). Ameren thus has included the effect of a non-cash item in the preparation of their cash working capital analysis. Even the title of the analysis, cash working capital, suggests having a non-cash item like uncollectibles influence the collection lag is a mistake. (*Id.* at 7:138-140). A mistake Ameren admitted on cross examination questioning. (Heintz, Dec. 15, Tr. 240). IIEC concludes that the calculation of Ameren's collection lag study is severely flawed since Ameren did not remove this significant non-cash item from the study. Ameren's calculated CWC result should be rejected.

In the collection lag study, Ameren witness Heintz used bill payment time periods to weight his CWC requirements beginning with current bills and going through payment periods of 0 to 30, 30 to 60, and 60 to 90 days. (Heintz, Dec. 15, Tr. 241-242). 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. (*Id.* at 242). Ameren multiplies the uncollectible percentage for each period times the test year revenue in each of the 0 to 30, 30 to 60, and 60 to 90 day bill payment periods. (*Id.* at 245). In doing so, Ameren assumed that each bill payment period contributed an identical percentage of its included revenues to the amount that ultimately becomes uncollectible. (*Id.* at 247). Ameren opines that this is a realistic assumption - even though Ameren admits they used the same percentage simply because they do not know, for each of the bill payment periods, the actual percentage of revenues that become uncollectible. (*Id.* at 249). This unsupported default assumption shoehorns bill payment periods of different size and age into the same circle.

Mr. Heintz admits that the size of the billing period revenue amount matters in the weighting that goes to that period. (*Id.* at 248). Ameren states the largest collection period is either the current period or the 0 to 30 day period. (*Id*. A 247-248). This weighting error is added to the weighting error that resulted from failing to remove uncollectibles from the analysis. (*Id.* at 248-249). Ameren'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 cash working capital analysis.

Ameren attempts to justify its admitted mistake of including a non-cash item in its analysis by presenting a calculation that multiplies "the uncollectible percentage that the Company calculates (test year net write-offs divided by test year revenues) by the revenues . . .then subtracting that amount from the revenues to get revenues net of uncollectibles." (Heintz, Ameren Ex. 53.0 at 8:166-169). Ameren's revised calculation purports to reduce the collections lag to 28.12 days compared to the filed 28.13 days. (*Id.* at 8:169-170). Ameren states the above calculation demonstrates that the inclusion of uncollectibles in the collection lag has no impact on the overall analysis. (*Id.* at 8:165-166). The calculation does not demonstrate a lack of impact on the analysis.

Only through the cross-examination of Ameren witness Heintz does the Commission learn that this purported validation is a meaningless, empty exercise. Ameren's validation calculation, which it claims shows that the inclusion of uncollectibles in the collection lag has no impact on the overall analysis, is inaccurate. (*Id.* at 8:165-166). Ameren claimed validation has simply reduced the percentage contributions of each bill payment period by the same factor - the percentage of revenues represented by uncollectibles. (Heintz, Dec 15, Tr. 251). The fact that the results are essentially equal proves nothing; it merely illustrates the mathematical truth that if one has a series of ratios and reduces each ratio in that series by the same percentage, the relationships of the ratios in the series will not change. (*Id.* at 251-252).

Because Ameren did not properly remove non-cash items from its study, Ameren's calculation of the collection lag study is severely flawed and should be rejected.

iii. The Collection Lag should be consistent with Commission Rules

The Commission's rules provide that for residential service, the due date for payment of customer bills may not be less than 21 days after the postmark on the bill, if the bill is mailed, or the date of delivery, if the bills is delivered by other means. (83 Ill. Adm. Code Section 280.90). For non-residential customers the due date for payment may not be less than 14 days. (*Id.*). However, Ameren's cash working capital allowance assumes a collection lag of 28.13 days. (Ameren, Heintz Ex. 4.0E at 8-9: 172-175). The collection lag recommended by IIEC is 21 days and is based on the Commission's rules. (IIEC, Meyer 3.0 at 4-5:74-85). The payment periods in the Commission rules represent a maximum payment period, not average or typical payment periods. (*Id.* at 5:84-85).

Ameren ignores the incentive customers have to pay their bills on time because of the ability to charge them a late payment fee. (*Id.* at 5:88-104). Ameren 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). Furthermore, 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. In addition, if one considers Ameren's total revenue and the percentage of that revenue that comes from the customer classes with a 14 day payment period, i.e., non-resiential customers, one would find that they pay approximately 48% of total revenues for AmerenIP; 57.4% for AmerenCIPS; and 56.1% for AmerenCILCO. (Meyer, IIEC Ex. 4.2). In this factual context, Ameren'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; any greater period would need to be further investigated and should not be accepted without more evidence than Ameren has provided. (*Id.* at 5:83-84).

iv. Conclusion

As shown in IIEC Exhibit 3.1, modifying the lag from 28.13 days to 21 days will reduce Ameren's CWC requirement for electric operations from $1,424,709 to ($12,357,593) for the three utilities combined. (IIEC, Meyer Ex. 3.0 at 6:121-124). This would reduce Ameren's electric operations rate base by $13,782,302. (*Id.* at 6:124). With regard to Ameren gas operations, the change in the collection lag results in a reduction in the CWC requirement in rate base from

$22,352,178 to ($1,718,543), for the three utilities combined. (*Id.* at 6:125-127). This would reduce Ameren's gas operations rate base by $24,070,721. (*Id.* at 6:127). Reflecting IIEC witness Michael Gorman's rate of return, adjusted for income taxes, these reductions in rate base will lower Ameren's electric revenue deficiency by $1,597,287 and Ameren's gas revenue deficiency by $2,788,531. (*Id.* at 7:128-130).

Therefore, IIEC recommends that a 21 day collection lag be used to determine Ameren's cash working capital. IIEC's recommendation is consistent with Commission rules and is conservative considering the relative brevity of the 14 day payment requirement for commercial and industrial customers and the weighting effect of the non-residential component of Ameren's revenues. By overstating the collection lag, Ameren has overstated its cash working capital requirement. The cash working capital requirement should be reduced as recommended by the IIEC.

III. OPERATING REVENUES AND EXPENSES

A. Overview

In this section of its brief, IIEC discusses and addresses the issue of uncollectible expense and the appropriate level of injuries and damages expense for Ameren's gas and electric operations. IIEC discusses as well issues relating to amortization of IP's merger expense. IIEC also addresses an adjustment to the amount of PURA Tax reflected in Ameren's electric revenue requirements.

B. Resolved Issues

5. Uncollectibles Expense

In the direct testimony of Greg Meyer, IIEC proposed the use of a three-year average (for the period 2006-2008) of actual net-writeoffs to determine the Ameren uncollectible expense. (Meyer, IIEC Ex. 3.0 at 2:25-27). In the rebuttal testimony of Ameren witness Ronald Stafford, Ameren revised its uncollectibles expense proposal to substitute year-to-date actual information for previously used budget amounts. (Stafford, Ameren Rev. Ex. 29.0 at 9:204-210). The effect of the Ameren revision was to eliminate the use of budgeted amounts as Mr. Meyer had proposed. During the cross-examination of Mr. Stafford, Ameren further clarified its position on calculation of its uncollectible expense. (Stafford, Dec. 15, Tr. 301-303). IIEC accepts Ameren's revised proposed uncollectibles expense as explained in the rebuttal and cross-examination testimony of Ameren witness Stafford.

C. Contested Issues

5. Amortization of IP Merger Expense/Regulatory Asset

In its direct case, Ameren proposed to continue its recovery of the amortization of the AmerenIP merger expense regulatory asset at current levels indefinitely. (*See* Everson, Staff Ex. 2 at 12:267-269; Everson, Staff Ex. 16.0 at 7:149-8:152). Since the rates in this proceeding are expected to be in effect beyond the ordered end date of the original amortization period, continuing recovery at the current level would almost certainly over-recover the asset amount over the period rates will be in effect. (*Id.*; Meyer, IIEC Ex. 3.0 at 10:203-212). IIEC proposed to adjust Ameren's amortization period and level to assure full recovery of the regulatory asset, while preventing over-recovery from ratepayers. (*Id.*).

In Finding (9) of the Commission's Order in Docket No. 04-0294, which approved the acquisition of IP by Ameren, AmerenIP was authorized to amortize $67 million of merger-related costs over four years.(Illinois Power Company and Ameren Corporation, ICC Dkt. 04-0294 Order Sept. 22, 2004 at 56). The amortization period began on January 1, 2007 and will expire December 31, 2010.

AmerenIP has included in its electric cost of service $11,848,950 and $4,901,050 in its gas cost of service for the merger expense amortization. (Meyer, IIEC ex. 3.0 at 10:186-187). This is a total of $16,750,000.

IIEC is proposing to amortize over two years the level of expense which will still need to be collected when new rates take effect in this case. For purposes of this adjustment, IIEC witness Greg Meyer assumed that rates in this case will become effective May 1, 2010. 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. This two year period is roughly consistent with the interval between Ameren's last rate case and this one, and is consistent with Ameren's proposed period for amortizing rate case expense in this proceeding. Meyer, IIEC Exhibit 3.4 shows the calculation of the electric and gas adjustments IIEC is proposing.

Unless an adjustment is made to this amortization, AmerenIP will continue to collect significant levels of revenues for an expense that has been fully amortized. During the first year rates approved in this case are in effect, AmerenIP electric operations will over-collect approximately $4 million in revenues. (Meyer, IIEC Ex. 3.4 at 1). Similarly, AmerenIP gas operations will over-collect approximately $1.6 million in revenues. (Meyer, IIEC Ex. 3.4 at 2). During the second year that rates approved in this case would be in effect, the electric operations would over-collect the entire $11.8 million and the gas operations would over-collect $4.9 million, or a total of $16.7 million. (Meyer, IIEC Ex. 3.0 at 11:208-211) The adjustment IIEC is proposing would certainly reduce or potentially eliminate this over-collection.

This adjustment continues to allow full recovery of the merger-related costs. However, it does not allow AmerenIP the opportunity to over-collect for these expenses for the next two years the new rates approved in this case are effective. Staff witness Mary Everson and AG-CUB witness David Effron reached the same conclusion and proposed distinct adjustments to achieve the same objectives. (Everson, Staff Ex. 2.0 at 12-13:263-286; Effron, AG-CUB Ex. 2.0 at 9:2-21).

In its rebuttal testimony, Ameren reacted to the objections to its amortization proposal with a slate of legalistic defenses. (Stafford, Ameren Rev. Ex. 29.0 at 31:707-721). Each defense was roundly criticized and effectively refuted in the rebuttal testimonies of the IIEC and Staff. (*See generally* Meyer, IIEC Ex. 7.0 at 9-13; Everson, Staff Ex. 16.0 at 7-11). Those witnesses pointed out fundamental flaws and errors in Ameren's positions and arguments. In addition, each witness explained how Ameren's own proposal failed to meet the strained interpretations of governing law and practice that Ameren sought to apply to the proposals of the non-utility parties.

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, it will begin to over-collect only $5.6 million of fully amortized merger-related expense on an annual basis. (Meyer, IIEC

Ex. 3.4 at 1, L14). 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 would urge the Commission to limit many, if not all, of the requests by AmerenIP to update their case through pro forma adjustments through May 2010. Specifically, 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.

8. Electric Distribution Tax/Public Utilities Revenue Act Tax

IIEC has recommended that Ameren's test year revenue requirements reflect the impact of credits or refunds of the PURA Tax to Ameren during the 2008 test year, to the extent such credits and refunds are not already reflected in the revenue requirement. (Stephens, IIEC Ex. 5.0-C at 18:358-359).

In response, Ameren witnesses have suggested in their surrebuttal testimony that a review of the history of the PURA Tax indicates that the Ameren Companies have received some level of refunds of this tax. Ameren states it therefore agrees with the proposal of IIEC witness Stephens to reflect the test year level of refunds as a reduction in the Company's requested revenue requirement. (Stafford, Ameren 2d Rev. Ex. 51.0 at 553-556). Ameren specifically has recommended 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. (Stafford, Ameren Ex. 51.13 at 1-3:Lin 6). Since these reductions are very close to the reductions recommended by IIEC witness Stephens, IIEC accepts the Company's proposed adjustment. However, IIEC has no position on whether an additional or further adjustment as proposed by the Staff is necessary.

Also, it should be noted that acceptance of a version of IIEC's recommendation on this revenue requirement adjustment does not resolve the issue of whether or not the Company's cost of service study needs to be adjusted to reflect this reduction in expense. IIEC addresses this issue in Section VII.C.2.b. of this brief.

11. Injuries and Damages Expense

Ameren proposed an adjustment to its 2008 Test year Injuries and Damages (I&D) expenses that would substitute the historical five-year average of actual payments for I&D claims, adjusted for inflation using the Consumer Price Index ("CPI") factor, in place of actual Test year expenses. For AmerenIP electric operations, a four-year historical average was utilized, also adjusted for inflation, to eliminate a year of outlier data. (Meyer, IIEC Ex. 3.0 at 7:136-140; Wichmann, Ameren Rev. Ex. 3.0E at 10:205-212). Through the testimony of its witness Greg Meyer, IIEC opposed Ameren's addition of an inflation adjustment to the consistent, systematic approach to annualizing I&D expenses the Commission has employed in at least the last two preceding Ameren rate cases. (Meyer, IIEC Ex. 3.0 at 8:142; Stafford, Dec 15, Tr. 342). Continued use of the Commission's customary, systematic approach will allow recovery of I&D expenses at a level that reflects Ameren's actual expenses. Modifying that level of expense using a CPI factor is unnecessary and inappropriate.

Ameren accepted Staff's proposed adjustment to remove certain Hazardous Materials costs from the calculation of normalized I&D expense. (Stafford, Ameren Rev. Ex. 29.0 at 6:143; Wichmann, Ameren Ex. 30.0 at 3:52). The acceptance of Staff's modification does not eliminate Ameren's inflation adjustment, and it does not change IIEC's opposition to the inflation adjustment.

Ameren's proposed adjustment is inappropriate for at least two reasons. First, the focus of Ameren's adjustment is wrong. Ameren explains the purpose of its addition of an inflation adjustment to the actual Injuries and Damages expenses it has incurred as follows: "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." (Wichmann, Ameren Ex. 30.0 at 3:60). The proper focus of the I&D expense item is not the level of time and material costs of the construction or other <u>activities</u> that may give rise to personal injury or property damages claims. Rather, I&D expense covers the costs of <u>resolving</u> the <u>claims</u> themselves. Indeed, if the simplistic relationship assumed by Ameren's adjustment actually existed, there would be few disputed I&D claims. Ameren could simply pay time and material costs for affected persons and property, rather than using investigations, negotiations, and litigation to minimize those expenses.

Second, the factual assumptions underlying Ameren's adjustment are not supported by any record evidence. The assumed, but unproven, relationship noted above is the prime example. As Mr. Meyer explained, "the level of actual I&D expense incurred in a year is more closely related to the number of claims filed and subsequently settled during a year." (Meyer, IIEC Ex. 7.0 at 2:41-

3:44). With respect the costs of the claims, "inflation is not a significant driver." (*Id.*) Furthermore, "[u]se of the inflation factor also has no effect or impact of (sic) on the number of claims processed." (Wichmann, Ameren Ex. 30.0 at 3:59). Faced with IIEC's challenge to the sole stated basis of its proposal, Ameren presented no evidence that would establish a relationship between the actual costs of resolving claims and the inflation of construction materials and labor costs.

Ameren acknowledges the fact that there are significant fluctuations in the levels of I&D expenses from year to year. (Wichmann, Ameren Ex. 30.0 at 3:56). In IIEC's view, such fluctuations, that are distinct from the rate of inflation, add support to Mr. Meyer's conclusion that inflation is not a driver of this category of expenses. 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.

Moreover, Ameren presented no quantitative evidence that the effects of inflation are not adequately reflected in the amounts for which it was able to settle I&D claims or in the Commission's traditional normalization through a multi-year average. Ameren provided no analysis or other evidence showing that Ameren 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. (Meyer, IIEC Ex. 7.0 at 3:47-53).

Mr. Meyer explained that if the Commission's consistent, systematic approach in past Ameren rate cases is continued, Ameren will recover an appropriate level of I&D expense. (Meyer, IIEC Ex. 7.0 at 3:47-53). Ameren has not presented an evidentiary basis for the Commission to displace that systematic approach already in place.

IV. COST OF CAPITAL/RATE OF RETURN

A. Overview

In this section of its brief, IIEC addresses the appropriate return on common equity for the Ameren Companies (gas and electric). In doing so it discusses the return on equity estimates made by Ameren and the use of the various models used to make return on common equity estimates as well as the component parts of those models. IIEC also recommends an overall rate of return for the Ameren Companies.

F. Cost of Common Equity

Through the testimony of IIEC expert witness Michael Gorman, IIEC recommends that the Commission approve a return on common equity ("ROE") of 10.0% for the electric and gas utility operations of each of the Ameren Companies. (Gorman, IIEC Ex. 2.0-C at 51). IIEC recommends an overall rate of return ("ROR") of 8.847% for AmerenIP, 7.866% for AmerenCIPS, and 8.453% for AmerenCILCO, based on IIEC's recommended ROE of 10.0%, and the distinct actual capital structures of each company, as of March 31, 2009. (Gorman, IIEC Ex. 2.1).

Through the testimony of Ameren witness Kathleen McShane, Ameren recommends ROEs in the range of 11.75% to 12.25% for Ameren electric operations and an ROE in the range of 11.25% to 11.60% for Ameren gas operations. (Gorman, IIEC Ex. 2.0 at 58:1266-1267). IIEC's Mr. Gorman reviewed Ms. McShane's testimony, exhibits, and supporting workpapers. Mr. Gorman concluded that the Company's ROE proposals are overstated and that they should be rejected.

(Gorman, IIEC Ex. 2.0 at 3:44). Staff witness Janice Freetly presents Staff's recommended costs of equity for the Ameren Companies: AmerenCILCO, 10.31% (electric) and 9.88% (gas); AmerenCIPS, 10.23% (electric) and 9.41% (gas); and AmerenP, 10.35% (electric) and 9.83% (gas). (Freetly, Staff Ex. 6.0 at 24:438-442).

2. Contested Issues

a. Return on Equity Estimates

The objective of the ROE witnesses in this proceeding was to estimate the market-required return on equity for the Ameren companies. The determination of an appropriate return is governed in part by two well-established decisions of the U.S. Supreme Court that are well-known to ROE experts: Bluefield Water Works & 398 Improvement Co. v. Public Serv. Commission of West Virginia, 262 U.S. 679 (1923) and Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944). (*See, e.g.*, Gorman, IIEC Ex. 2.0-C at 17:397; McShane, Ameren Rev. Ex. 12.0E at 3:45). Under those decisions, a utility should be authorized a return sufficient to maintain its financial integrity and to attract capital at reasonable terms. The return should be commensurate with returns investors could earn by investing in other companies of comparable risk. (Bluefield Water Works & 398 Improvement Co. v. Public Serv. Commission of West Virginia, 262 U.S. 679, 692, 693 (1923); Federal Power Commission v. Hope Natural Gas Co. 320 U.S. 591,603 (1944)).

IIEC recommends that the Commission approve a return on common equity ("ROE") of 10.0% for the electric and gas utility operations of each of the Ameren Companies. (Gorman, IIEC Ex. 2.0-C at 51:1127-1138). Mr. Gorman's recommended ROE is a conservative estimate. A comparison to Staff's recommended ROEs shows that Staff witness Janice Freetly's cost of equity estimate for gas operations is slightly lower, and her estimate for electric operations is slightly higher. (Freetly, Staff Ex. 6.0 at 2:26-31).

To estimate the Ameren Companies' cost of equity, Mr. Gorman used a combination of analytical models. Employing a constant growth discounted cash flow ("DCF") model, a sustainable growth DCF model, a multi-stage growth DCF model, and a capital asset pricing model ("CAPM"), Mr. Gorman developed a return on common equity consistent with the governing legal standards. Because the Ameren 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 the Ameren Companies. (Gorman, IIEC Ex. 2.0-C at 18:413-415). Mr. Gorman used the electric and gas proxy groups developed and presented in the direct testimony of the Company's witness Kathleen McShane. (Gorman, IIEC Ex. 2.0-C at 18:418:-419).

Before adopting those proxy groups, Mr. Gorman confirmed the similarity of the risk of the Ameren Companies and the proxy groups. The electric proxy group had an average senior secured credit rating from S&P ("BBB+") identical to S&P's senior secured credit rating for AmerenCILCO (BBB+) and AmerenCIPS (BBB+), and comparable to AmerenIP's credit rating of "BBB." Mr. Gorman also found the proxy group's senior secured credit rating from Moody's ("A3") to be reasonably comparable Moody's senior secured credit rating for the Ameren Companies ("Baa1"). On the basis of his assessment of equity ratios and business risk profiles of the electric proxy group and the Ameren Companies, Mr. Gorman found that they are comparable in risk. (Gorman, IIEC

Ex. 2.0-C at 18:422-19:442). Similarly, he found that the equity ratios, business risk profiles, and bond ratings of his gas proxy group are comparable. (Gorman, IIEC Ex. 2.0-C at 19:445-20:463). Based on these analyses, Mr. Gorman concluded that the electric and gas proxy groups had comparable investment risk to that of the Ameren Companies. Mr. Gorman performed his various cost of equity analyses on these electric and gas proxy groups. (Gorman, IIEC Ex. 2.0-C at 18:413-415).

i. Discounted Cash Flow Model Analyses

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 rate of return. (Gorman, IIEC Ex. 2.0-C at 21:467). That theory has been accepted in the Commission's repeated reliance on DCF estimates as a basis for its cost of equity determinations.

The constant growth version of the DCF model assumes that earnings and dividends will grow at a constant rate. The model requires a current stock price, expected dividend, and expected growth rate in dividends. (Gorman, IIEC Ex. 2.0-C at 20:466-482, 22:500-501). 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. (Gorman, IIEC Ex. 2.0-C at 22:504-514). For the dividend input to the model, he used the most recently paid quarterly dividend reported in the Value Line Investment Survey. (*Id*. at 22:515-518).

Constant Growth DCF (Analysts Growth) -- 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. (Gorman, IIEC Ex. 2.0-C at 23-24:533-545). His 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. (Gorman, IIEC Ex. 2.0-C at 24-25:560-563).

However, Mr. Gorman concluded that this version of the constant growth DCF analysis produced unreliable results. First, Mr. Gorman observed 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 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. (Gorman, IIEC Ex. 2.0-C at 26:588-591, 28:635, 28:644-650). The U.S. economy is projected to grow at a rate of 5% over the next 5-10 years. (*Id*. at 28:645). 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. (*Id.* at

24:550-557) 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. 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. (Gorman, IIEC Ex. 2.0 at 29:653-663).

These dividend yield and growth factors are also inconsistent with each other, as they reflect contradictory outlooks for the utility industry. (*Id*. at 25:567-574). 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. (*Id*.). Thus, Mr. Gorman 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. (*Id*.). Specifically, Mr. Gorman noted that the historic dividend yields for his proxy groups were significantly lower than the current dividend yields for those groups. He opined 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. (Gorman, IIEC Ex. 2.0-C at 26:588-602).

Constant Growth DCF (Sustainable Growth) -- Mr. Gorman’s second version of the constant growth DCF model used the same inputs as the first, with the exception of the growth rate input. There Mr. Gorman used a sustainable growth rate proxy for the expected growth rate. (Gorman, IIEC Ex. 2.0-C at 32:738-740). To develop this input, Mr. Gorman used an internal growth rate methodology that included 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. (*Id*. at 30-31:694-702). 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. (*Id.* at 31-32:703-730). 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. (*Id*. at 32:733-737).

Multi-Stage Growth DCF Model -- 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. Analysts' growth rate projections are intended to be a reflection of rational investment expectations over only the next 3 to 5 years. A constant growth DCF model cannot 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. (Gorman, IIEC Ex. 2.0 at 33:743-749). His 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. (*Id.* at 33:751-761). For the other model inputs, Mr. Gorman used the same 13-week stock price and quarterly dividends used in his constant growth DCF models. (*Id*. at 34-35:775-782).

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. (Gorman, IIEC Ex. 2.0-C at 35-36:784-802).

DCF Analysis Results -- 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. Mr. Gorman excluded the unreasonable results of the constant growth DCF based on analysts' growth projections. (*Id.* at 36:804-808).

ii. Capital Asset Pricing Model Analyses

Mr. Gorman also relied on a capital asset pricing model (CAPM) analysis to develop his recommended return on common equity for the Ameren Companies.[3] The underlying theoretical

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[3] In addition, Mr. Gorman performed two versions of a Risk Premium analysis, but did not use the analyses as support for his recommended cost of equity. (Gorman, IIEC Ex. 2.0-C at 41:924). Although the Commission has traditionally not relied on risk premium analyses, Mr. Gorman’s Risk Premium result (10.0%) is consistent with his recommendations here.

basis for the CAPM method is that the market requires a return on a security investment that is equal to a risk-free rate of return plus a market risk premium, adjusted for a particular stock's risk relative to the overall market risk. The relationship between risk and return is expressed mathematically as: Ri = Rf + Bi x (Rm - Rf) where:

Ri equals required return for stock;

Rf equals risk-free rate;

Bi equals Beta-measure of risk of stock; and

Rm equals expected return on the market.

(Gorman, IIEC Ex. 2.0-C at 42:936-947).

Because the risk-free rate is typically represented by U.S. Treasury securities, Mr. Gorman used Blue Chip Financial Forecasts' projected 30-year Treasury bond yields for his risk-free rate. (Gorman, IIEC Ex. 2.0-C at 43:966). The Beta term in his CAPM analysis is the average *Value Line* Beta estimate for his electric and gas proxy groups of comparable companies. (*Id*. at 44:985). 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. (*Id*. at 44-45:990-1001). 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. (Gorman, IIEC Ex. 2.0-C at 45:1002-1006).

Because of concerns the Commission has expressed in the past about the use of only historical data in cost of equity analyses, Mr. Gorman confirmed 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. (Gorman, IIEC Ex. 2.0-C at 47-50:1048-1107).

Mr. Gorman's CAPM analyses for his proxy groups produced a midpoint return on equity estimate of 9.43% for his electric group and 9.01% for his gas group. (Gorman, IIEC Ex. 2.0-C at 50:1118-1122).

iii. Return on Equity Recommendation

Based on the analyses discussed above, Mr. Gorman recommends a cost of equity for the Ameren Companies 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%. (Gorman, IIEC Ex. 2.0-C at 51:1137). Because Mr. Gorman's recommended return on common equity is based on the cost of equity for Companies with risks similar to that of the Company, it is commensurate with returns investors could earn by investing in other enterprises of comparable risk and will allow capital to be attracted to the Company under reasonable terms.

As discussed below, a 10.0% return on common equity will also allow the Company 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 cited earlier.

Mr. Gorman assessed the adequacy of his recommended return on common equity by comparing key financial ratios for Ameren 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. (Gorman, IIEC Ex. 2.0-C at 52:1142-1149). Mr. Gorman constructed the S&P financial ratios for the Ameren utility operations using their utility operations cost of service data (not parent company financials) their respective proposed capital structures, and his return on common equity of 10.0%. (*Id.* at 53:1174).

Mr. Gorman's analysis demonstrated that AmerenIP would be provided with the opportunity to produce a Funds From Operations ("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). The Company's total debt to total capital ratio would be 54%. This is within the old ranges for "BBB" rated utilities. (Id.). Finally, the Company's retail operations FFO to total debt coverage would be 14%, which is within the new ranges for "BBB" rated utilities. (Gorman, IIEC Ex. 2.0-C at 54-55:1197-1216).

Mr. Gorman's analysis showed that AmerenCIPS would have the opportunity to produce an FFO to debt interest expense coverage ratio of 5.7x. This interest coverage ratio is above the high end of the old range for "BBB" rated utility companies (2.8x to 3.8x) and above the high end of the new range (2.0x to 3.5x). It will support a strong "A" credit rating. The Company's total debt to total capital ratio would be 47%. This is within the old ranges of 42% - 50% for "A" rated utilities. Finally, the Company's retail operations FFO to total debt coverage would be 28%, which is within both the new and the old ranges for "A" rated utilities. (Gorman, IIEC Ex. 2.0-C at 55-56:1220-

1238).

For AmerenCILCO, Mr. Gorman's analysis showed 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). The Company's total debt to total capital ratio would be 54%. This is within the old ranges for "BBB" rated utilities. Finally, the Company's retail operations FFO to total debt coverage would be 18%, which is within both the old and new ranges for "BBB" rated utilities. (Gorman, IIEC Ex. 2.0-C at 56-57:1242-1262).

Thus, Mr. Gorman's recommended return on common equity for Ameren (10.0%) will allow each of the Ameren utility operations to maintain its financial integrity.

Mr. Gorman's DCF and CAPM analyses updated to reflect more recent information, also support his recommended return on equity of 10.0%. (Gorman, IIEC Ex. 6.0-C at 3:39-53).

b. DCF and CAPM Issues

Through the testimony of its witness Kathleen McShane, the Ameren Companies recommend that the Commission approve a return on equity in the range of 11.75% to 12.25% for AIU's electric utility operations and a return on equity in the range of 11.25% to 11.60% for AIU's gas utility operations. Ms. McShane's return on equity recommendation was based on three DCF analyses, several risk premium studies, and a CAPM analysis. (Gorman, IIEC Ex. 2.0-C at 58:1266, 58:1272; *also see, e.g.*, McShane, Ameren Rev. Ex. 12.0E at 4, Table 1). She also included in 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. (McShane, AmerenIP Rev. Ex. 12.0E at 4; AmerenCIPS Rev. Ex. 12.0E at 4; AmerenCILCO Rev. Ex. 12.0E at 4; AmerenIP Rev. Ex. 12.0G at 4; AmerenCIPS Rev. Ex. 12.0G at 4; AmerenCILCO Rev. Ex. 12.0G at 4; Gorman, IIEC Ex. 2.0-C at 59:Table 5).

Mr. Gorman explained that Ms. McShane's DCF return estimates were overstated because they relied on growth rates in the constant growth rate DCF model that exceed reasonable estimates of long-term sustainable growth. Further, Ms. McShane's DCF return estimates reflect dividend yields affected by the recent stock market downturn. Those excessive growth rates are examined in the immediately following “Growth Rates” sub-section.

Ms. McShane stated that Mr. Gorman’s sustainable growth DCF model was in error because it did not include the external financing component. (McShane, Ameren Ex. 36.0 at 22:422). However, as Mr. Gorman discussed the external financing component was excluded because it indicated negative growth, which he concluded was not reasonable. (Gorman, IIEC Ex. 6.0-F at 9:147). In fact Mr. Gorman updated his sustainable growth DCF model to include the external financing model and it actually resulted in lower DCF return estimates. (Gorman, IIEC Ex. 6.0-C at 8:144-146 and Table 3).

Ms. McShane’s capital asset pricing model also produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group. Ms. McShane's CAPM return estimates for her gas group were in the range of 9.8% to 10.7%. (Gorman, IIEC Ex. 2.0-C at 59: Table 5). Her high estimates are attributable primarily to her use of an overstated market risk premium. (*Id.* at 63:1340). The pervasive effects of her excessive market risk premium in her CAPM analysis are discussed further below.

As in past cases, Ameren again proposes to inflate these already flawed cost of equity estimates, to take account of the difference between (i) Ameren's equity ratios computed using the book value of its equity share and (ii) those ratios when computed using the market values of equity shares. The Commission has repeatedly rejected numerous variations of such "leverage" adjustments that artificially boost the amount on which a utility earns a return. (Gorman, IIEC Ex. 2.0-C at 76:1622-1625, 77:1637). A simple a recalculation of equity ratios does not change the amount actually invested to provide service to customers, and on which the utility is permitted to earn a return. (220 ILCS 5/9-211).

Ms. McShane proposes a market-to-book ratio adjustment in the range of 0.00% to 0.50% for electric and 0.75% to 1.10% for gas, calculated to account for this difference in market value and book value equity. (Gorman, IIEC Ex. 2.0-C at 76:1616). Mr. Gorman noted that Ms. McShane acknowledges that the Commission has repeatedly rejected her proposed market value adjustment. He also observed that Ameren has not presented any new evidence that should alter the Commission's position. (*Id.* at 76:1623). Ameren's proposed market to book value adjustment should be rejected.

Ms. McShane also estimated a return on equity 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. (Gorman, IIEC Ex. 2.0-C at 78-70:1652-1675). IIEC witness Mr.

Gorman noted 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. (Gorman, IIEC Ex. 2.0-C at 79-80:1679-1696). Hence, the Commission should reject this flawed methodology, as it has done consistently in the past, and IIEC will not discuss it further.

c. Growth Rates

Ms. McShane performed several DCF analyses. Presumably, she did that for the same reasons that Mr. Gorman performed multiple DCF analyses -- to take account of the current unsustainable nature of analysts' growth estimates. Ms. McShane acknowledges, as the Commission has found, that long-term growth is effectively capped by GDP growth. (McShane, AmerenIP Rev. Ex. 12.0E at 32-33:637-647; *In re Nicor*, Dkt. 08-0363, Order, Mar 25, 2009 at 70). Current analysts' growth projections are higher than comparable GDP projections. (Gorman, IIEC Ex. 2.0-C at 28:645). Her analyses reflect this same understanding; her sustainable growth DCF model analyses are distinct from her constant growth (analysts' rates) DCF model.

Ms. McShane's estimates of growth are too high to be reasonable estimates of long-term sustainable growth. Ms. McShane's constant growth DCF returns on equity were 13.6% for her electric group and 10.8% for her gas group. (Gorman, IIEC Ex. 2.0-C at 60:1283-1286). These returns were based on group average growth rate estimates of 7.1% and 5.3%, respectively (McShane, AmerenIP Ex. 12E.6; AmerenCIPS Ex. 12E.6; AmerenCILCO Ex. 12.6; AmerenIP Ex. 12G.6; AmerenCIPS Ex. 12G.6; and AmerenCILCO Ex. 12G.6). These growth rate estimates are far too high to be reasonable estimates of long-term sustained growth. As Mr. Gorman explained, it is not rational to expect that a utility company can grow indefinitely at a rate greater than the U.S. economy. U.S. economic growth is projected to be about 5.1% over the next 5 to 10 years. (Gorman, IIEC Ex. 2.0-C at 28:645). The growth rates used by Ms. McShane as sustainable growth rates far exceed the rate of growth of the U.S. economy. Therefore, the results of Ms. McShane's constant growth DCF model are not reliable in today's market.

Yet, Ms. McShane incorporated the outlier result of that analysis using analysts' short-term forecasts (acknowledged unsustainable growth rates) in the development of her recommendation to the Commission. (Gorman, IIEC Ex. 2.0-C at 61:1307-1311). 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. That 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. Ms. McShane used the excessive result of that flawed model in developing her ultimate cost of recommendation. (*See, e.g.*, McShane, Ameren Rev. Ex. 12.0E at 4, Table 1).

Ms. McShane's DCF estimates also suffer from a more serious flaw - her use of stock prices that reflect anomalous market indicators from the recent financial crisis. (Gorman, IIEC Ex. 2.0-C at 62:1313-1331). Dividend yields calculated using stock prices from that period are unrepresentative of the improved financial environment. Simply using a more recent period that reflects the continuing market recovery would produce significantly lower (approximately 70 basis points) dividend yields for her proxy groups.

Mr. Gorman concluded that Ms. McShane's use either the inflated yield or the inflated growth rate is an adequate, independent ground for rejecting Ms. McShane's DCF estimates. Her DCF estimates should not be considered in the Commission's determination of Ameren's cost of equity.

e. Market Risk Premium

Ms. McShane's capital asset pricing model also produced an excessive return on common equity, in the range of 10.1% to 11.2% for her electric group. (Gorman, IIEC Ex. 2.0-C at 63:1337). Ms. McShane's CAPM return estimates for her gas group were in the range of 9.8% to 10.7%. (Gorman, IIEC Ex. 2.0-C at 59, Table 5). These estimates are the result of her use of significantly overstated market risk premium inputs. Mr. Gorman testified:

> I take issue with two primary aspects of Ms. McShane's CAPM analysis. First, in her historical CAPM analysis, Ms. McShane's estimated a market risk premium of 6.25% to 6.5%. That estimate is inflated and should be adjusted, because it reflects the total return on Treasury securities instead of only the income return. Second, Ms. McShane's forward CAPM is based on a market risk premium of 9.1%, which also is inflated, flawed and should be rejected.
> (Gorman, IIEC Ex. 2.0-C at 63:1340-1345).

Ms. McShane developed two estimates of the market risk premium. Her first estimate was based on a forward-looking equity risk premium. 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. (Gorman, IIEC Ex. 2.0-C at 63-64:1348-1354). Her second estimate was based on the difference between the total achieved return on equity securities and the income return on 20-year Treasury yields over the period 1926 through 2008. That produced an equity risk premium of 6.5%, which was comparable to the result (6.25%) of a similar analysis based on a 1947 through 2008 time frame. (Gorman, IIEC Ex. 2.0-C at 64:1355-1359).

The forward-looking market risk premium was calculated on the basis of her constant growth DCF return on the market of 13.8%. (Gorman, IIEC Ex. 2.0-C at 62:1362-1369). This DCF return on market was largely driven by a long-term sustainable growth rate of approximately 10.1% and dividend yield of approximately 3.7%. Such growth is more than twice the estimated growth rate of the overall U.S. economy. 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. (*Id.*).

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. (Gorman, IIEC Ex. 2.0-C at 65:1382-1390). Subtracting Ms. McShane's risk-free rate of 4.7% resulted in a market risk premium would be 5.1%, significantly lower than Ms. McShane's forward-looking market risk premium estimate of 9.1%. (Gorman, IIEC Ex. 2.0-C at 64:1354).

Ms. McShane also developed a historical market risk premium in the range of 6.25% to 6.5%. This estimate was based on the difference between the total achieved return on equity securities and the income return on 20-year Treasury yields over the period 1926 through 2008.

That 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 Mr. Gorman noted that despite Ms. McShane's flawed estimation process of subtracting only the income return (instead of the total return) on the 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. (Gorman, IIEC Ex. 2.0-C at 66-67:1398-1422).

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. That means those risk free rates are not representative of costs during the period rates are in effect and is not appropriate in setting rates that recover AIU's costs of service during that period. Further, he noted that this risk-free rate significantly exceeds the current long-term Treasury yields in the range of 4.0% to 4.5% and the projected long-term Treasury yield of 5.0% over the next two years. (Gorman, IIEC Ex. 2.0-C at 67:1425-1436).

Using a market risk premium in the range of 5.8% to 6.0%. a projected two-year 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 return on equity of 9.2% and 8.89%, respectively, as recommended by IIEC. (Gorman, IIEC Ex. 2.0-C at 68:1440-1445).

Staff's cost of equity recommendation is similarly flawed by reliance on an overstated market risk premium in its CAPM analysis. Staff witness Ms. Freetly recommended a return on equity based on a non-constant DCF model and a CAPM risk premium analysis. (Freetly, ICC Staff Ex.

6.0 at 2:34-40). 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%. Ms. Freetly's market return of 12.70% implies a dividend yield of 2.2% and a growth rate above 11.0%. (Gorman, IIEC Ex. 6.0-C at 13:250-14:256). Mr. Gorman noted that this growth rate estimate was more than twice the expected long-term growth rate of the U.S. economy and produced 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. Inconsistently, in her risk premium study she used a growth rate that is too high to be a reasonable long-term growth rate estimate. (Gorman, IIEC Ex. 6.0-C at 14:259-270).

g. Other

Like Mr. Gorman, Ms. McShane also developed a risk premium return estimate. As noted earlier, Mr Gorman recognized that the Commission has traditionally relied on DCF and CAPM analyses, declining to consider risk premium estimates. Ms. McShane, however has incorporated the results of her risk premium analyses in her recommended cost of equity estimate. (McShane, Ameren Rev. Ex. 12.0E at 59:1178). The effect is to add another high result to boost the overall level of the collection she uses to support her recommendation. Ms. McShane developed two risk premium Though the Commission is unlikely to use Ameren’s historical risk premium estimates in its own determination of the appropriate cost of equity, IIEC notes, nonetheless, that each is flawed. (*See*, Gorman IIEC Ex. 2.0-C at 68-75:1446-1605).

Mr. Gorman noted that Ms. McShane’s Baa (7.25%) and A (6.9%) utility yields used in her electric and gas historical risk premium studies is unreliable because she uses only forecasted interest rates. The accuracy of forecasted interest rates is highly problematic. Therefore, current observable and forecasted interest rates should be used to enhance the reliability of the return estimate. (Gorman, IIEC Ex. 2.0-C at 72-73:1523-1548 and IIEC Ex. 2.23).

Ms. McShane also developed a DCF-derived risk premium return estimates of 11.8% and 9.8% for electric and gas, respectively. (Gorman, IIEC Ex. 2.0-C at 74). Mr. Gorman noted that these return estimates are also based on projected "Baa" and "A" yields and suffer from the same flaws discussed above in respect to Ms. McShane's historical risk premium. (Gorman, IIEC Ex. 2.0-C at 75:1586). Using her electric equity risk premium of 4.2% and her gas equity risk premium of 2.9% and the current "Baa" and "A" utility yields of 6.5% and 5.8% would result in a return on equity for AIU of 10.7% and 8.7% for electric and gas, respectively. (Gorman, IIEC Ex. 2.0-C at 75:1586-1592).

Overall, with just and reasonable adjustments to Ms. McShane's return on equity studies produces a return of 9.9% for AIU electric and 9.6% for AIU gas. (Gorman, IIEC Ex. 2.0-C at 75:1600-1605). Therefore, IIEC's recommended return on equity of 10.0% is a fair compensation for AIU's shareholders, will not place a significant burden on the ratepayers, and should be adopted by the Commission.

G. Recommended Overall Rate of Return

Based on IIEC’s recommended return on common equity of 10.09% and the proposed capital structure of each Ameren Company, IIEC recommends an overall rate of return for AmernIP of

8.847%, Ameren CIPS of 7.866% and AmerenCILCO of 8.453%. (Gorman, IIEC Ex. 2.1).

V. PROPOSED RIDERS

A. Overview

Ameren Companies originally proposed to collect the PURA Tax through the Tax Additions Rider - Rider TA. IIEC opposed the recovery of the PURA Tax through a rider.

B. Resolved Issues

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

As noted above, IIEC opposed the collection of the PURA Tax through Ameren's Tax Additions Rider - Rider TA. As IIEC witness Stephens and Staff witness Lazare pointed out, the PURA Tax does not vary significantly from year-to-year. (Stephens, IIEC Ex. 1.0-C at 26:553-559, Lazare, Staff Ex. 7.0 at 12:266-267). The taxes are not large relative to the overall expenses of the Ameren Companies. (Stephens, IIEC Ex. 1.0-C at 26:553-554). For these reasons, and for the other reasons identified in Mr. Stephen's testimony. IIEC opposed collection of the PURA Tax through the rider. (Stephens IIEC Ex. 1.0-C at 24-27:515-583).

In its rebuttal testimony, Ameren agreed not to pursue recovery of the tax through a rider at this time. (L. Jones, Ameren 2d Rev. Ex. 40.0 at 2:36-38). However, Ameren supports Staff's recommendation to collect the tax on a cents per kWh basis in base rates. (*Id*. at 3:58-67).

IIEC agrees that rider recovery of the tax is inappropriate and should be rejected by the Commission for the reasons identified by IIEC witness Stephens and Staff witness Lazare. However, collection of the tax on a cents per kWh basis, as a separate line item charge, as proposed by the Staff , would produce the same divergence from cost-based ratemaking and the same horrendous delivery service rate increases for large high load factor customers, such as the IIEC Companies in this case, as Ameren's original proposal to collect the tax on a cents per kWh basis through Rider TA. Staff's approach also makes rate moderation extremely difficult, if not impossible. Therefore, Ameren's agreement to forego rider recovery in this case, does not resolve, in any way, IIEC's concerns about recovery of the tax from Ameren customers on a cents per kWh basis, under any circumstance. IIEC addresses these concerns in Section VII.C.2.c. of this brief.

VI. COST OF SERVICE/REVENUE ALLOCATION

A. Overview

In the presence of valid ECOS studies, the IIEC Companies in this case support cost allocation and rate design practices that allow price signals to flow undistorted between utility service providers, such as the Ameren Companies, and the consumers of those services. In addition, they support cost based rates, to the maximum extent possible, taking account of traditional rate design principles, such as rate continuity, gradualism, and avoidance of rate shock. Furthermore, the Commission has long followed the consistent and well reasoned policy of moving utility rates to cost of service, thereby giving appropriate price signals. (*See*, Illinois Power Company, ICC Dkt. 93-0183, 1994 Ill. PUC LEXIS 139*184-186; Central Illinois Light Company, ICC Dkt. No. 94-0040, 1994 Ill. PUC LEXIS 577, *158 and Northern Illinois Gas Company, ICC Dkt. No. 95-0219, 1996 Ill. PUC LEXIS 204, *109-110, – accepting interclass revenue allocations that decreased subsidies.).

Two notable exceptions to the Commission's policy are its decisions in the most recent Ameren Companies' delivery service rate cases, ICC Docket. 07-0585, et al, and Commonwealth Edison Company's (ComEd's) delivery service rate case, ICC Docket 07-0566. In the Ameren case, even though a valid and largely uncontested ECOS study was in the record, the Commission approved an across the board rate increase, stating as follows:

> 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 [Ameren] 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.
>
> * * *
>
> 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.
> (Illinois Power Company, d/b/a AmerenIP, et al., ICC Dkt. 07-0585, et al., (Cons.), Order, Sept. 24, 2009 at 279-280) (emphasis added).

Thus, just over one year ago, the Commission ordered across-the-board rate increases for Ameren customers. Similar circumstances apply in this case, but make the need for an across-the-board rate increase even greater. First, the delivery service rate increases for certain classes and subclasses in this case are far greater than in Docket 07-0585, making the need to ease rate impacts even more important. Second, the ECOS studies in this case are significantly different than what Ameren presented in Docket 07-0585, et al; they are highly contested and contain numerous errors and inconsistencies, some of which did not become known until the evidentiary hearings in the case, as will be discussed at length below.

In the ComEd case, Docket 07-0566, as in this case, the ECOS study was hotly contested. The Commission found that ComEd's cost study was not suitable for rate-setting. As a result, it moved rates only a modest step, i.e. 25 percent of the way, toward "cost," as calculated by ComEd's flawed study, and initiated a separate rate proceeding to address the flaws in ComEd's study. (Commonwealth Edison Company, ICC Dkt. 07-0566, Order, Sept. 10, 2008 at 213).

In the above recent decisions, the Commission deemed it necessary to temporarily set rates that do not, or may not, reflect cost of service. The extraordinary rate shock introduced by Ameren in this case, and the problems with Ameren's ECOS studies, would justify a similar ruling by the Commission in this case.

C. Contested Issues

1. Electric

a. AIU's Cost of Services Studies

Ameren Companies have presented three ECOS studies in this proceeding, one for each company. An ECOS study is used to allocate revenue requirements or cost responsibility among customer classes and subclasses. It compares the cost each customer class or subclass imposes on the system, to revenues produced by each class or subclass. A properly performed cost study shows the cost to serve each class or subclass and the rate of return for each class or subclass under current rates. Customer classes or subclasses with a rate of return equal to the total system rate of return are paying their cost of service. Customer classes paying less than their total system rate of return are not paying their cost of service. (Stowe, IIEC Ex. 4.0 at 3:50-54).

There are three steps in a properly performed cost of service study. The first step is the functionalization of costs. In this step, costs are distinguished according to major functions such as production, transmission, distribution and customer service. (*Id*. at 4-5:68-89).

The second step in a cost of service study is the classification of the costs functionalized in the first step. These costs are classified on the basis of cost causation principles. For example, costs may be classified as demand-related, energy-related or customer-related. (*Id*. at 5:90-100).

The third and final step is the allocation or assignment of costs that have been functionalized and classified in Steps 1 and 2, to the customer classes and subclasses. This is done based on allocation factors that comport with the cost causation principles used to classify the costs in the second step. (*Id*. at 5:101-105).

As noted above, separate ECOS studies were presented for each Ameren Company in this proceeding. These studies purport to show the total company rate of return and the class (including subclasses) rates of return for each company and each customer class (or subclass) within each company. (*Id*. at 6-7:115-120).

However, the results of any cost of service study are only as valid as the inputs and assumptions used to develop the study. (*Id*. at 7:121-124). As mentioned above, the Commission itself has stated that its policy is to set rates as close as possible or appropriate to cost of service, but in order "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." (Illinois Power Company, d/b/a AmerenIP, et al., ICC Dkt. 07-0585, et al., (Cons.), Order, Sept. 24, 2009 at 279).

Unfortunately, the Ameren studies in this case contain errors in logic and factual inconsistencies that render them deficient for the purpose of setting rates in this proceeding. Some of these errors and inconsistencies were identified in IIEC's direct and rebuttal testimony and others have been exposed and identified through cross-examination and a review of the rebuttal and surrebuttal testimony of Ameren's cost of service witnesses.

The initial group of errors and inconsistencies was identified in IIEC's direct testimony. The first error was the misallocation of the cost of 34.5 kV and 69 kV substations to customers taking services at a voltage of 100 kV or higher. The second involved the misallocation of PURA Taxes. The third involved errors in the development of the non-coincident peak ("NCP") demand allocators. (Stowe, IIEC Ex. 4.0 at 2:30-39). The fourth involved failure to properly allocate transformer rental revenue.

IIEC re-ran the Ameren cost of service studies to correct for the first two deficiencies set forth above. (Stowe, IIEC Ex. 4.0 at 14-16:256-283). The correction of these two deficiencies alone had a significant impact on the class rates of return and the revenue allocations in each of the

Ameren studies. Showing, for example, that the DS-4 class as a whole provided higher rates of return than Ameren'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 Ameren Companies. (Stowe, IIEC Ex. 4.0 at 15:Table 3). IIEC did not receive the data it needed to modify the NCP demand data allocators from Ameren in a timely manner, and was therefore, unable to correct the third deficiency in the ECOS study. (*See*, Stowe, IIEC Ex. 4.0 at 15:267-272).

Subsequently, based on its review of the rebuttal and surrebuttal testimony of certain Ameren witnesses and cross-examination conducted in this case, IIEC has identified additional inconsistencies and errors. Testimony provided during the cross-examination by Ameren's cost of service witness contradicts this witness' pre-filed testimony, further demonstrating Ameren's ECOS studies are flawed and unreliable.

Ameren performed demand studies different from those used in Ameren's last rate case to develop the demand allocators used as part of the cost of service studies presented in this case. (Althoff, Ameren Ex. 41.0 at 7:136-148). The new demand studies lead to the misallocation of secondary costs to primary customers. The Ameren demand studies also cause the ECOS studies to fail to allocate costs of poles, wires and substations to 2000 large customers taking service at secondary voltage. Also the Ameren ECOS studies contain problematic class definitions, and fail to properly distinguish between customer demand at supply voltage, delivery voltage and metered voltage in the context of the study. Finally, the Ameren ECOS studies fail to properly allocate transformer rental revenues to the classes.

All of the errors and inconsistencies are discussed in greater detail in Subparts b, c, d, e and f below.

When all of these errors and inconsistencies are considered, the fundamental validity and accuracy of the Ameren cost of service studies are called into question. Unfortunately, analyses or alternate versions of the cost studies, such as IIEC's, that are based on Ameren's flawed ECOS studies are themselves flawed (although perhaps to a lesser degree). Under the circumstances, the Commission cannot be sure that the cost of serving the classes and subclasses within each Ameren Company have been accurately and properly determined.

Therefore, it is IIEC's primary recommendation in this case that the Commission reject the use of the Ameren cost of service studies 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 the cost studies for rate design and revenue allocation purposes, the studies should be corrected for at least the deficiencies identified by IIEC.

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

c. Allocation of Cost of Primary Distribution Lines and Substations

Among the errors and inconsistencies identified by IIEC in the Ameren ECOS studies, was the improper allocation of costs of substations operating at sub-transmission voltages (i.e., 34 kV and 69 kV). The Ameren cost studies allocated these sub-transmission costs to transmission level customer classes that take service at 100 kV or higher. (Stowe, IIEC Ex. 4.0 at 8:141-144). IIEC suggested that in total, Ameren's cost studies improperly allocated $27.5 million in primary voltage and/or sub-transmission voltage substation equipment costs to transmission level customers.[4] (Stowe, IIEC Ex. 4.0 at 11:177-179). IIEC pointed out that the mis-allocation of these costs appeared to be associated with a change in the allocation factor used to distribute sub-transmission (34 kV and/or 69 kV) station equipment in the current studies. In the current studies, Ameren used a factor identified as "DEMSUBTR". IIEC also pointed out that in its prior studies Ameren had used an allocator identified as "DDSUBTR". The difference between the allocator used in the current studies and the allocator used in the past studies, is that the allocator used in the past studies correctly did not allocate the cost of 34 kV and 69 kV substation equipment to 100 kV and above customers, while the new allocator does. Accordingly, Mr. Stowe corrected for the mis-allocation in the revised cost studies. (Stowe, IIEC Ex. 4.0 at 14:257-263).

Initially, Ameren disputed IIEC's criticism of its study in this regard. However, during cross-examination in this case, Ameren witness Althoff finally conceded the error in the Ameren cost of service studies in this regard and indicated that Ameren would use factor DDSUBTR to allocate the cost of 34 kV and 69 kV substation equipment that IIEC argued had been misallocated. (*See*, Althoff, Dec. 16, Tr. 570-571). However, the correction of this error does not resolve all of the errors and inconsistencies in the Ameren cost of service studies identified by IIEC and discussed below. Nor does Ameren's concession help the Commission's determination of cost of service based on Ameren' studies since the admission and change occurred at the time of cross-examination and the record was soon after closed without any modification to the Ameren electric cost of service

[4] IIEC described the specific percentage and dollar value of the mis-allocation for each of the Ameren Companies in its direct testimony. (*See,* Stowe, IIEC Ex. 4.0 at 10:169-176).

studies to correct the allocation. (*See*, Althoff, Dec. 16, Tr. 580-581).

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

Since the 1970 elimination of the Personal Property Tax, Illinois utilities have been subject to a tax on invested capital, pursuant to the Public Utilities Revenue Act (PURA), (35 ILCS 620/1 et seq.). Prior to 1998 for electric utilities (and to date for natural gas utilities), the tax was assessed at a rate of 0.8 percent of the utility's invested capital. In conjunction with Electric Service Customer Choice and Rate Relief Law of 1997 (the Restructuring Law - Public Act 90-561), the Illinois Legislature determined that it would change the basis of the 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. (35 ILCS 620/1a.) The PURA Tax tier levels and the rates were custom-designed to collect approximately the same level of tax revenue from each utility, and in total, as the utilities paid previously, based on invested capital. This design also 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 present Ameren Companies was about $23 million for AmerenIP, $9 million for AmerenCIPS (including the former Union Electric Company) and $4 million for AmerenCILCO, as detailed by IIEC witness Stephens. (Stephens, IIEC Ex. 5.0-C at 14:Table 1).

As a protection for utilities and their customers, the Restructuring Law capped the aggregate level of electric PURA Tax that the state could collect at $145,279,553 in 1998, adjusted for growth in subsequent years at the lesser of 5% or the percentage increase in the Consumer Price Index. Tax payments in excess of the cap in any year were to be refunded to the utilities, through the provision of credit memoranda, in proportion to the utilities' respective payments of PURA Tax to the total tax collected in the year. (35 ILCS 620/2a.1.(c)). The cap has been exceeded in every year since 1997, through the year 2007, prompting the annual proportional refunds, and this is likely to be the case for the foreseeable future. (Stephens, IIEC Ex. 1.0-C at 21:444-448).

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 cost of service studies based on the classes' share of the cost of utility plant in service, since plant in service represented the capital investments of the utilities.[5] The PURA Tax was restructured in 1997, but in each of the delivery service rate cases initiated by the Ameren Companies or their unaffiliated predecessors since 1997 (12 cases in all) the PURA Tax has been allocated on the basis of plant in service. (Stephens, IIEC Ex. 1.0-C at 17-18:376-385). In the current case, however, Ameren proposes to change its allocation from one based on plant in service to one based on the number of kWh delivered to each class. (L. Jones, Ameren Rev. Ex. 16.0E at 8:139-150). This proposal would have the effect of shifting millions of dollars of revenue responsibility, from the smaller customer classes to the large customer classes. The change in allocation also accounts for much of the large increases in delivery service charges proposed by Ameren for the DS-4 customers, particularly those taking service at higher

[5] The tax has been recovered through base rates along with the rest of the utility revenue requirement, not a rider. (*See*, L. Jones, Dec. 14, Tr. 108-109).

voltages. (Stephens IIEC Ex. 1.0-C at 3:54-56; Lazare ICC Staff Ex. 7.0 at 10-11:224-233; L. Jones, Ameren 2d Rev. Ex. 16.0E at 9:151-158).

In addition to allocating the PURA Tax cost on the basis of energy, instead of plant in service, in its direct testimony, Ameren originally proposed to recover the cost of the tax through a rider. Recovery under the rider was based on an equal cents per kWh charge for all customers, with over- and under-recoveries trued up to actual expenditures each year. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 13-14:240-260). In rebuttal testimony, Ameren stated it would not pursue rider recovery in this case. (L. Jones, Ameren 2d Rev. Ex. 40.0 at 2:36-38). Ameren accepted the recommendation of ICC Staff, to recover the Tax through an equal cents per kWh charge as a separate line item on customers' bills, but without a true-up of recoveries to costs. (Lazare, Staff Ex. 7.0 at 11-12:252-265). IIEC opposed the rider recovery approach and opposes the separate line item recovery approach, as discussed in Sections V.B.2. and VII.C.2.c. of this brief, respectively.

IIEC opposes Ameren's proposed change in the allocation of the PURA Tax for the reasons identified below.

First, Ameren has not provided sufficient justification for departure from the Commission's established method of allocation of this tax for the Ameren Companies. Indeed, the affirmative evidence in the case supports retention of the current allocation method.

Second, expenses should be allocated in a cost of service study based on cost causation. The test year PURA Tax responsibility of the Ameren Companies is based primarily on the invested capital tax levels in 1997, which were based on the utilities plant in service levels at that time. This is unquestionably true for PURA Tax responsibility up to the 1997 levels (approximately 84% of the test year PURA Tax expense), but is also true of growth in the PURA Tax above 1997 levels. Therefore, plant in service remains the proper allocator of PURA Tax and Ameren's proposal should be rejected.

Third, the assertions of Ameren and Staff that a utility's PURA Tax expense is purely or clearly a function of kWh sales ignores the history of the tax, the several other factors that affect the tax levels and the undisputed evidence in the record that PURA Tax responsibility for Ameren is not even well correlated to its kWh sales.

Fourth, the Illinois Legislature indicated in the 1997 Deregulation Law that it was interested only in "maintaining a comparable allocation among electric utilities in the State for payment of [PURA] taxes.. . ." (35 ILCS 620/1a) (explanation added). It did not give any indication that in modifying the collection structure, it intended to have the Commission shift cost burdens among customer classes.

In light of the law and evidence on this issue, no change is warranted in this case, and the entire PURA Tax expense should be allocated among the classes based on plant in service. However, should the Commission wish to change the allocation method of the PURA Tax expense to reflect kWh levels of the classes, IIEC recommends an alternative position whereby the 1997 levels of PURA Tax for each utility are allocated on the basis of utility plant in service, and PURA Tax amounts in excess of the 1997 levels are allocated based on kWh sales.

i. Ameren's Change to PURA Tax Allocation is Not Justified.

Ameren has not justified a change to the long-standing, consistently used (twelve Commission cases) PURA Tax allocation. (*Id*. At 17-18:376-385). The testimony in support of the change in Ameren's allocation of PURA Tax was provided by Ameren witness Mr. Leonard Jones. His entire stated rationale for the change is the following sentence:

> The annual distribution tax is assessed to the AIUs based on the quantity of retail electricity delivered in Illinois, making it clearly driven by kWh sales and not based on plant assets. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 8:141-143).

Ameren was asked to provide all relevant memoranda, meeting minutes, analysis, etc. prepared or authored by any Ameren Company or Ameren Services Company employee determining that its traditional approach is no longer appropriate. Ameren indicated that it did not have any documents or other material responsive to this request. (Stephens, IIEC Ex. 1.0-C at 19:393-402). Ameren's entire meager rationale for its change is ignorance of the cause and origin of the tax, and the factually incorrect belief that the tax is "clearly driven by kWh sales." Ameren also identified no change in law or administrative rule that would explain or justify abandonment of its well established PURA Tax allocation in this case.

In his direct testimony, IIEC witness Stephens explained why the tax level is not "clearly driven by kWh sales". He explained 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. The main factor determining a utility's PURA Tax responsibility today is the utility's 1997 level of invested capital (and associated tax). The tiers levels and tier rates in the PURA 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. The taxes actually paid on invested capital – caused the tiered kWh assessments, the kWh assessments do not determine the amount a utility pays. The higher a utility's level of invested capital in 1997, the larger its PURA Tax responsibility today, irrespective of its current kWh deliveries. (*Id*. at 20; Stephens IIEC Ex. 5.0-C at 10:186-198; *See also* Lazare, Staff Ex. 21.0 at 4:69-72 -- "[Mr. Stephens] is right in stating that: (1) the distribution tax was previously determined by the levels of investment plant, and (2) the initial levels of the taxes paid by individual utilities were based on previously calculated amounts determined by their respective plant investment levels.").

For example, if a utility's 1997 invested capital had been double its actual amount, its 2008 PURA Tax responsibility would be approximately doubled as well. This is because the marginal tax *rate*, applicable to a utility today, was determined in 1997 and was custom-designed to recover the 1997 level of revenues from each utility. There is a clear causal link between a utility's 1997 level of invested capital and its PURA Tax payment today. Similar causality cannot be attributed to kWh sales. If a utility's kWh sales were to instantly double, its PURA Tax burden would not double. The utility's tax liability is based on the utility's proportional share of the total statewide PURA Tax. This proportional, rather than absolute, tax responsibility is confirmed by ICC Staff witness Lazare:

> If a utility's level of deliveries goes up *relative to other electric utilities* in Illinois, its share of distribution taxes will increase. If its

> *relative level* of deliveries decline, the utility's share of the distribution tax total will fall. (Lazare Staff Ex. 21.0 at 5:106-108) (emphasis added).

Thus, Mr. Lazare implicitly recognizes that a utility's PURA Tax burden depends at least as much on the taxes paid by the other utilities as it does on its own kWh deliveries.

IIEC witness Stephens examination of the dynamics of PURA Tax determination showed why a utility's PURA Tax burden is not "clearly driven by kWh sales" and how an increase in a utility's kWh sales could lead to a *decrease* in the utility's PURA Tax burden, depending on the level of tax paid by the other utilities in the state. (Stephens, IIEC Ex. 1.0-C at 22:461-477, Stephens IIEC Ex. 1.3). He found that:

> [I]n years when the PURA Tax cap is exceeded, e.g. every year to date, a utility's tax burden is dependent more on its proportional share of tax payments, considering the rest of the utilities, than it is on changes in its own kWh deliveries. (Stephens, IIEC Ex. 1.0-C at 23:479-481).

Ameren'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. The proposed change is not justified.

ii. The Actual Numbers Do Not Support Ameren's Claim.

Contrary to Ameren's and Staff's suggestion, any correlation between kWh sales and the utilities' PURA Tax liability in a given year is very weak. That was Mr. Stephens' finding when he analyzed the actual kWh sales reported by the Ameren Companies and the actual PURA Tax payments. Mr. Stephens explained that if "the level of usage determines the amount of [PURA] taxes," as claimed by Mr. Lazare, or if the taxes were "clearly driven by kWh sales," as Mr. Jones claims, one would expect a linear positive relationship between PURA Tax and kWh deliveries, with the slope of the line representing the marginal (last block) tax rate. (Stephens, IIEC Ex. 5.0-C at 11-12:228-232). However, the actual data of the Ameren Companies, shown in IIEC Ex. 5.1, prove that this is far from the case. The "coefficient of determination," or explanatory value, of kWh changes to changes in PURA Tax range from about 0.09 to 0.19, (on a possible scale of 0 to 1). The determined range of values delivered indicates a very weak explanative value of kWh deliveries for changes in the PURA Tax. (Stephens, IIEC Ex. 5.0-C at 12:233-238). Also, 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 kWhs the utility delivers change at different rates. This is another indicator of lack of correlation between the kWh sales and expected tax levels. (Stephens, IIEC Ex. 5.0-C at 11-12:238-249; Stephens, IIEC Ex. 5.1). Thus, kWh deliveries do not explain (cause) the levels of the PURA Tax paid by utilities in any given year, because they are only very weakly correlated.

The analytic evidence provided by IIEC was unrebutted by Ameren or Staff, who relied instead on the simplistic, but 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. Ameren's only attempt at rebuttal was its observation that one Illinois utility has been allowed to allocate PURA Tax on the basis of kWh sales. Ameren could provide no evidence that any other electric utility in the State, all of which have delivery service rates, has ever allocated the

PURA Tax on the basis of energy deliveries. (L. Jones, Ameren 2d Rev. Ex. 40.0 at 26:547-553).

iii. The Large Majority of Current PURA Tax is Simply Inherited 1997 Invested Capital Tax.

IIEC witness Stephens testifed that approximately 77% of the PURA Tax assessed to the Ameren Companies in 2008 was attributable directly to their 1997 invested capital taxes. However, as he noted in his rebuttal testimony, this percentage was based on 2008 PURA Tax payments, without recognition of credit memoranda (i.e., refunds) for 2008. (Stephens, IIEC Ex. 5.0-C at 13-14:265-271, Table 1). In surrebuttal testimony, Ameren revised downward its 2008 test year revenue request for PURA Tax expense to reflect such refunds and credit memoranda for the test year. (Stafford, Ameren 2d Rev. Ex. 51.0 at 24:539-543; Stafford Ameren Ex. 51.13). On the basis of Ameren's revised test year 2008 PURA Tax expenses, approximately 84% of the test year PURA Tax for the Ameren Companies was inherited from the 1997 invested capital tax.[6] Given the Commission's commitment to cost causation principles in setting rates, (*See*, *e.g.*, Illinois Power Company, ICC Dkt. 93-0183, Ill. PUC Lexis 139* 184-186). it would be unreasonable and patently unfair to allocate the PURA Tax entirely on the basis of energy usage, when nearly 84% (or 77%) of the tax is caused by historical utility plant investment unrelated to energy delivery. Furthermore, as discussed previously, even the growth in tax liability post-1997 is closely tied to 1997 invested

[6] The 84% is calculated in the same manner as in Table 1 of Mr. Stephens' Rebuttal Testimony, IIEC Ex. 5.0-C, but with updated 2008 figures per Ameren Surrebuttal testimony, Ameren's total test year 2008 PURA Tax expense, per Mr. Stafford's Surrebuttal Testimony is $42.96 million. (Stafford, Ameren Ex. 51.13, lines 3 summed). The total percentage is calculated as follows:

> $36.04 million (1997 total, per IIEC Ex. 5.0-C at 14:Table 1) divided by $42.96 million (above) = 84%.

capital levels, through the utility-specific tax rates.

The record in this case contains, inter alia, unrebutted evidence that the level of the tax is primarily a function of the amount of the 1997 invested capital tax, and IIEC's analysis showing that a utility's tax liability is not tied directly to a utility's kWh sales, and the percentage of PURA Tax directly attributable to historical invested capital taxes. There is virtually is no evidence to compel a change in the allocation of this significant cost item. Ameren has failed to meet its burden to justify the proposed deviation from the Commission's long-standing practice for almost all Illinois utilities in this regard. Indeed, the affirmative evidence adduced in the case strongly supports maintaining the current allocation.

iv. The Proposed Tax Allocation is Inconsistent with the Legislative Approach to the PURA Tax.

Ameren's proposed allocation of the PURA Tax is not consistent with the legislature's approach to maintain the 1997 invested capital tax levels and utility shares. Section 1a of the PURA describes the legislative intent of the PURA which was introduced as part of the 1997 Restructuring Law. That statement of legislative intent follows:

> Sec. 1a. Legislative Intent. 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. (35 ILCS 620/1a) (emphasis added).

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. Nowhere in the law is there expressed an expectation that the redesign could shift tax burdens from one customer class to another.

It was necessary for the legislature 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 ICC, and might not own physical assets. The new suppliers would enter the Illinois market to compete against utilities or other suppliers, who owned such assets – that would have been subject to the invested capital tax. Moreover, the 1997 Restructuring Law allowed utilities to sell or transfer capital assets to affiliated or unaffiliated third parties, with very limited Commission overright. (*See*, 220 ILCS 5/16-111(g)). Thus, 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.

The structure of the statute indicates the Legislature also wished to maintain tax revenues as comparable to the amount collected before the change in the law. (35 ILCS 620/1a, et seq.). As Mr. Stephens explained, since the invested capital of the utilities in 1997 caused a specific level of PURA Tax for each utility, 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. The same level of tax can be derived under any number of custom approaches; the Illinois Legislature happened to use the custom-designed per kWh approach. (Stephens, IIEC Ex. 5.0-C at 10:187-198). For the most part, the basis for the tax - and the cause of the utility cost incurred and recovered in rates - did not change. The approach chosen by the legislature simply to maintain tax revenue stability does not dictate a shift in cost responsibilities among customer classes.

The legislature's objective of "maintaining a comparable allocation among electric utilities" of the PURA Tax was achieved by custom-designing the tier sizes and rates to match the utilities 1997 taxes. (*See*, 35 ILCS 620/2a.1; Stephens, IIEC Ex. 1.0-C at 20:424-426, Fn. 16). These rates, tied to 1997 invested capital tax levels, ensured the comparable allocation among the utilities intended by the legislature.

The Legislature's obvious desire to maintain historic tax burdens, and allocations among the state's utilities should be a guide in the allocation of PURA Tax. In all but the words used in a custom-designed re-calculation, the invested capital tax was preserved by the legislature. Certainly the cause of the costs incurred by utilities is substantially unchanged. There is no basis for altering how the PURA Tax is allocated among each utility's customer classes, or recovered by the Ameren

Companies, through rates. The initial PURA Tax levels for each utility and the statewide cap on the tax were established in 1997. The basis for the tax level and the apportioning of tax burdens among utilities was the amount of (and assessment on) utilities' invested capital. The associated capital assets, such as generation, transmission and distribution facilities were traditionally allocated among rate classes using a demand-based allocation factor, not on energy or kWh delivered. (L. Jones, Dec. 14, Tr. 112-113). With the notable exception of Ameren's proposal for the PURA Tax in this case, costs attributed to utility assets are still allocated on the basis of demand. The resulting plant in service proportions have been the logical basis for allocating the PURA Tax responsibilities, by tying the cost recovery to the cost causation. Thus, continued use of distribution plant in service proportions to allocate the PURA Tax "maintains a comparable allocation" among customer classes, just as the legislature intended for the Illinois utilities.

v. Alternative Tax Allocation Proposal

As explained previously in testimony and above, the Ameren Companies' levels of PURA Tax that existed in 1997 constitutes about 84 percent of the 2008 PURA Tax, and were not caused by kWh deliveries. Thus, there is no record evidence to support an energy based allocation of PURA Taxes up to the 1997 starting levels, which constitute a perpetuation of 1997 invested capital taxes. The simplest and most equitable approach is to leave in place the current allocation method, based on distribution plant in service for the entire PURA Tax expense. However, if 84% of a cost being attributable to a single cause element is not enough for the Commission to determine a reasonable allocation basis for the entire cost, IIEC submits an alternative, even more precise cost-causation allocation method.

For growth in PURA Tax above 1997 levels, many factors affect the utility's tax level. These include the marginal tax rates (which also tie back to 1997 invested capital tax levels), the initial level of the statutory cap on statewide collections, (also based on the 1997 invested capital tax levels) the applicable CPI measure, the statutory escalation rate (5%), and the PURA Tax payments of all of the other Illinois utilities (even in prior years). In addition, energy deliveries (kWh) affect the incremental portion of the tax above the 1997 levels. (Stephens, IIEC Ex. 1.0-C at 23:490-501; Stephens, IIEC Ex. 5.0-C at 11:213-217, Fn 7).

If the Commission decides that some portion of the PURA Tax should be allocated on some basis other than plant in service, 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 cost of service study, 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 Ameren Companies necessary for implementation of this approach are shown in Table 1 of Mr. Stephens' Rebuttal Testimony.[7] (Stephens, IIEC Ex. 5.0-C at 14-15:272-302, Table 1). IIEC computed revised cost of service results based on this alternative approach and provided them in IIEC Ex. 5.2.

This alternative approach provides a reasonable and practical compromise position on this contentious issue, should the Commission seek such a compromise. It correctly reflects the causative factors of 84 percent of the PURA Tax (on average) for the Ameren Companies, but provides for a portion of the tax that may be affected by kWh deliveries to be allocated based on energy. As the utilities' overall tax burden grows, the portion of the tax allocated on energy would grow as well. (Lazare, Dec. 14, Tr. 128-129). While this method is not as correct as maintaining the current allocation method for the 2008 PURA Tax expense, it is far superior to changing the allocation of PURA Tax to one with very little causative basis. This approach actually phases in energy allocation over time, in relation to the only portion of the tax that appears to be caused by energy deliveries in any way and minimizes the significant customer impacts associated with an energy-only allocator.

e. NCP Class Demands

There are two non-coincident peak demand issues addressed by IIEC in this portion of the brief. The first deals with the error in Ameren's cost of service study that incorrectly imputes NCP demand values that could not have occurred, to certain customer classes. The second deals with Staff's proposal to use coincident peak ("CP") demands to allocate the cost of primary lines and

[7] As mentioned above, Ameren updated its proposed 2008 tax year PURA Tax expense in surrebuttal testimony. The updated figures shown in Ameren witness Stafford's Ameren Ex. 51.13, line 3 should be used for the 2008 PURA Tax, and the post-1997 tax amounts recalculated accordingly.

substations. (Lazare, Staff Ex. 7.0 at 9:186-189).

i. The incorrect imputation of NCP demand values

Ameren has imputed NCP demand values at secondary voltage levels to primary voltage level customer classes. (Stowe, IIEC Ex. 4.0 at 13:239-242). The studies also impute NCP demands at primary and secondary voltage levels to customer classes served at sub-transmission voltage. (*Id*. at 13:242-244). Lastly, customer classes served at voltages of 100 kV and above are imputed demands at voltages below 34.5 kV. (*Id*. at 13-14:244-247). As a result, Ameren's cost of service studies over-allocate costs to Ameren's non-residential customers. While IIEC was not able to correct Ameren's ECOS study for this error, it does note that as a result of these errors, the Ameren cost of service studies over-allocate costs to the non-residential customers and, therefore, do not accurately determine the cost of serving those customers. It is therefore, unreasonable to rely on the Ameren cost of service studies for rate design and revenue allocation purposes in this case.

ii. Staff's proposed use of coincident peak demand

Staff has proposed the use of the CP method rather than the NCP method to allocate the cost of primary distribution lines and substations. (Lazare, Staff Ex. 7.0 at 9:186-189). Specifically, the Staff believes the coincident peak allocation reflects the causation of the costs associated with primary distribution lines and substations more accurately than the NCP allocation. (Lazare, Staff Ex. 7.0 at 6:118-124).

The Staff is wrong. The premise of the Staff's argument is that the CP method is more cost-based because it reflects the collective demands of multiple rate classes. (Stowe, IIEC Ex. 8.0-C at

20:458-460). The premise of Staff's argument is incorrect. Contrary to Staff's suggestions, 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. (*Id*. at 20:460-463). This is best illustrated by the Staff's discussion of how the NCP method penalizes the lighting class. The Staff's discussion ignores the fact that in the Ameren cost of service studies, the CP method does not recognize that the DS-5 rate (lighting) classes have any demand whatsoever. Under the Staff's approach, these classes would not be allocated any portion of the cost of primary lines and substations. (*Id*. at 20-21:464-489). Obviously, it is necessary to use primary lines and substations to serve the DS-5 rate class. 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. (*Id*. at 22:493-497). Clearly, NCP is more accurate than the CP method for allocation of the costs of primary lines and substations.

f. Other

In addition to the errors and inconsistencies in the Company's cost of service study discussed in Subparts a, b, d, and e above, IIEC has identified other errors and inconsistencies in the Ameren cost of service studies.

i. Erroneous Demand Studies

As noted above, Ameren performed new demand studies as part of its embedded cost of service analyses, claiming that these new studies better represent cost causation due to the recognition of class demand at supply and delivery voltages. (Althoff, Ameren Ex. 41.0 at 7:146-147). Ameren's witnesses suggested that the new demand studies are much more reflective of the demand incurred on the secondary voltage portion of Ameren's distribution system with respect to the DS-2 class. (Althoff, Ameren Rev. Ex. 56.0 at 12:257-258). However, 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. The study does not distinguish between DS-2 customers taking service at primary voltage and DS-2 customers taking service at secondary voltage. (Althoff, Dec. 16, Tr. 582-585). Therefore, 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.

ii. Discrepancies in Customer Counts

Also, there is a discrepancy in the number of DS-2 customers identified by some of the Ameren cost of service studies. The AmerenIP cost of service study identifies 69,275 DS-2 customers. (Althoff, Dec. 16, Tr. 582-583, IIEC Althoff Cross Ex. 1, P. 118, Ln. 19, Col. 19). However, Ameren's cost of service witness has testified that there are actually 65,402 AmerenIP DS-2 customers. (Althoff, Dec. 16, Tr. 584-585; Althoff, Ameren Rev. Rev. Ex. 56.0 at 12:255-260). Ameren was not able to state which number was correct. (Althoff, Dec. 16, Tr. 585). Thus, the Ameren study may fail to account for 3,972 DS-2 customers. (*See*, Althoff, Dec. 16, Tr. 584).

iii. Failure to Allocate Cots in Several FERC Accounts to Secondary Customers

Furthermore, the Ameren studies do not allocate costs relating to substation equipment, the cost of poles, towers and fixtures, overhead conductors and devices and underground conduit reflected in FERC Accounts 362, 364, 365 and 366 to 1,936 AmerenIP DS-3-a, DS-3-b, and DS-4 secondary customers. (Althoff, Dec. 16, 585-589). A similar situation occurs in the Ameren CIPS and the AmerenCILCO embedded cost of service studies. (Althoff, Dec. 16, Tr. 592). Ameren suggested 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. (*See,* Althoff, Dec. 16, Tr. 619). However, Ameren's response calls into question class definitions in the Ameren embedded cost of service studies. If classes clearly identified in the study as "secondary" are, in fact, supplied at primary voltage levels, it is not clear how one can possibly determine, based on the study, whether secondary and primary costs have been properly allocated.

iv. Ambiguous Customer Voltage Definitions

In addition, it is worth noting that Ameren indicated during cross-examination that the voltage levels discussed in its cost of service studies are actually "metered" voltage levels, which, according to Ameren, are totally separate and different from supply voltage and delivery voltage as Ameren has used those terms, in this case. (Althoff, Dec. 16, Tr. 586-587). Ameren did not explain the significance of the term "metered voltage" in its description of its embedded cost of service studies. (*See*, Althoff, Ameren Ex. 17.0E 41.0 and Rev. 56.0). This adds additional confusion to the Ameren studies which Ameren witnesses claim better represent cost causation due to recognition of class demands at supply and delivery voltages.

Ameren's suggestion that its cost of service studies reflect metered voltages is also confusing in that in other portions of its presentation to the Commission, it has suggested 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 Company's facilities. (Althoff, Ameren Ex. 41.0 at 7:152-155). In its surrebuttal testimony, Ameren implied that the designations of "secondary" and "primary" in its cost of service studies were designations of the "delivery" voltages for the customer classes. (Althoff, Ameren Rev. Ex. 56.0 at 12:259-260). Yet, as noted above, during cross-examination, the Ameren cost of service witness indicated that the term "secondary" for the DS-3a secondary, DS-3b secondary, and DS-4 secondary customer classes refers to "metered voltage", which had nothing to do with delivery and supply voltages. (Althoff, Dec. 16, Tr. 586-587). Under the circumstances, it is difficult to see how the Commission can determine whether or not the Ameren cost of service studies in this case have properly identified the cost of serving these customer classes.

v. Misallocation of Line Transformers and Services

Furthermore, the suggestion that DS-2 secondary, DS-3 secondary and DS-4 secondary customers are being allocated the appropriate portions of distribution system costs because they are allocated FERC Account 368 - Line Transformers and FERC Account 369 - Services - is misplaced for several reasons. First, line transformers are connected to the distribution system by primary and secondary wires (overhead conductors or underground cable), but the Ameren studies allocate neither overhead conductors (FERC Account 365) nor underground cables (FERC Account 367) to these customers. Second, Account 369 - Services - includes ". . . the cost installed of overhead and underground conductors leading from a point where the wires leave the last pole of the overhead system, or the distribution box or manhole, on top of the pole of the distribution line, to the point of connection with the customer's outlet or wiring." (18 C.F.R. pt. 101 (2009)). FERC Account 369 facilities begin where FERC Accounts 364 and 367 facilities end. An allocation of Account 369 costs does not equate to an allocation of distribution lines from the rest of the system as Ameren has suggested. Thus, the Ameren cost studies do not allocate any portion of the distribution system's poles, overhead conductors (wires), and underground cable, to the DS-3a, DS-3b and DS-4 secondary customers, thereby calling into question the ability of the Commission to determine whether or not Ameren's cost of service studies accurately measure class cost of service.

vi. Misallocation of Transformer Rental Revenue

Lastly, the new Ameren demand studies are inappropriately used to assign transformer rental revenues to the classes. IIEC witness Stowe identified an error in the way the Ameren cost of service studies credited transformer rental revenues to the customer classes. (Stowe, IIEC Ex. 8.0-C at 13-15:295-343). Ameren suggested that it would review the allocation of the rental revenues generated for transformation service in its next electric delivery service rate case to determine whether or not another allocation factor can be developed to better apply these rental revenues to the rate classes in which they are received. (Althoff, Ameren Rev. Ex. 56.0 at 17:368-371). In doing so, Ameren agreed that the revenues in question should be credited as closely as possible to the classes from which those revenues are collected. (Althoff, Dec. 16, Tr. 594-595). However, in the Ameren cost of service studies, the transformer revenues were allocated on the basis of each class' contribution to NCP demand as determined by the new demand studies. (Althoff, Dec. 16, Tr. 595). As a result of Ameren's improper treatment of rental revenues, customer classes from which rental revenues are collected do not receive the full credit of that revenue. This in turn understates the rate or return developed in the Ameren cost of service studies 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. (Stowe, IIEC Ex. 8.0-C at 15:338-343). Ameren's willingness to correct this error in the next case does little to help the Commission determine the cost of serving these classes in this case.

In sum, the Ameren cost of service studies contain numerous errors and deficiencies which affect the ability of its studies to accurately measure the class cost of service for each customer class. Under the circumstances, IIEC cannot support Ameren's studies, nor fully support any studies based thereon. The Commission should reject the use of Ameren's cost of service study for rate design and revenue allocation purposes in this case and implement rates on an across-the-board basis in this case. If the Commission determines to use the Ameren ECOS studies in any event, it should, at a minimum, direct Ameren to correct the allocation of substation costs to the DS-4 100 kV and above customer subclasses, correct the allocation of the PURA Tax in this case and correct the allocation of transformer rental revenues. The Commission should also direct Ameren to correct the other errors and deficiencies in its next delivery service rate case.

VII. RATE DESIGN/TARIFF TERMS AND CONDITIONS

A. Overview

With regard to electric issues, in this section of its brief, IIEC addresses rate moderation and mitigation, the appropriate class rate increases in this case, the appropriate recovery of the PURA Tax and the distribution delivery charges for DS-3 and DS-4 customers. IIEC also proposes modification of Ameren's *Standard Terms and Qualifications for Electric Service* to permit combined billing of multiple meters. Lastly, IIEC discusses the extension of the rate limiter for grain drying customers.

With respect to gas issues, IIEC notes in the prior proceeding of the Ameren Companies, many changes were proposed to the natural gas tariff terms and conditions by Ameren. IIEC addressed those issues through testimony, cross-examination and briefs. The primary issues that IIEC focused on were balancing terms and conditions and storage banks.

The Commission rejected most of the more onerous changes proposed by Ameren Companies in those proceedings and Ameren has not proposed similar changes in this proceeding. For that reason IIEC did not present testimony on natural gas rate design issues in this proceeding, but addresses certain items in this brief, as discussed below.

C. Contested Issues

1. Gas

d. Transportation Tariff (Rider T)

(1) Unbundling Banking Rights

Commission Staff witness Sackett proposed in his direct testimony that the Commission should:

> "Require the Companies to unbundle Rider T's bank from base rates in the next rate case and work with Staff and intervenors in the interim to determine equitable methods of allocating both storage capacity and costs." (Sackett, Staff Ex. 14.0 at 4:68-70).

IIEC strongly supports the concept of workshops prior to Ameren's next proceeding to consider these issues and hereby requests to be included in any such workshops. 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, there is no guarantee that customers will truly realize any unbundling of assets approved by the Commission.

In his rebuttal testimony, Mr. Sackett clarifies his proposal concerning the Transportation Tariff as follows:

> "I recommend that the Commission require the Companies to work with Staff and Intervenors to develop an equitable allocation process for storage assets, to allow customers to select the level of banking that best suits their needs, and to develop an equitable allocation of the costs of providing those services. The Companies should be required to propose these changes in their next rate case." (Sackett, Staff Ex. 27.0R at 33-34:734-737)

In his surrebuttal testimony, Ameren Witness Dothage supports the workshop process proposed by Staff (Dothage, Ameren Rev. Ex. 64.0 at 13:278). Although it appears that Mr. Dothage does not foresee the same outcome of the process, Ameren does support the workshop concept as a forum for resolving issues concerning customer use of Ameren's storage capacity.

IIEC recommends that the Commission adopt Staff's proposal as clarified by Mr. Sackett in ICC Staff Exhibit 27.0R and requests to be included in such workshops.

2. Electric

a. Rate Moderation/Mitigation Approaches

It is a widely held ratemaking policy that rates should be designed to reflect cost causation, maintain gradualism and avoid rate shock. Ameren's approach to revenue allocation fails to achieve any of these design goals, and as such is totally inadequate. First, as discussed in section VI of this brief, it is not based on a proper cost of service study. Second, it does not adequately apply the ratemaking concepts of gradualism and rate moderation. (Stephens, IIEC Ex. 1.0-C at 29:619-624). The Commission recognized this in its decisions in the last Ameren and ComEd delivery cases, Dockets 07-0585, et al and 07-0566, respectively, discussed in Section VI . A. above. The ICC Staff agrees that class revenue increases should be constrained to limit the impacts on ratepayer bills of any increase approved in this case. As Mr. Lazare states, bill impacts have been a major concern for Ameren ratepayers since the expiration of the rate freeze in January 2007 and they remain a concern in this case as well. (Lazare, Staff Ex. 7.0 at 16:351-354).

Through its proposed rates, Ameren has requested unprecedented levels of rate increases for its largest, highest load factor customers. IIEC provided evidence that some customer subclasses would receive increases in their delivery service bills of several hundred percent to over 1,200 percent, under Ameren's proposal. (Stephens, IIEC Ex. 1.0-C at 6-7:146-170; *See*, Sec I. A). In testimony that appears to contradict its rate proposal, Ameren alleges that bill impacts are a concern to it, and thus has proposed the "moderated" rates as it did. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 10:172-175). Indeed, Ameren claims that it has "proposed to mitigate the rate changes to customer classes due to bill impact concerns." (*Id.* at 47:992-993). According to Mr. Jones, "the total increases to DS-4 would have approached 100% if not for the proposed revenue allocation limitation." (*Id.* at 10:174-175). Apparently, a 100% increase to a rate class is of concern to Ameren, but increases of 500% to over 1200% to certain subclasses are not. (*See*, Stephens, IIEC Ex. 1.0-C at 6-7:151-160). This exposes a fundamental flaw in Ameren's approach, which will be discussed below. Unfortunately, Ameren has done an exceedingly poor job of mitigating the delivery service cost increases for the DS-4 class in general and the higher voltage DS-4 sub-classes and customers in particular.

The two main failings in Ameren's alleged 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. (Stephens, IIEC Ex. 1.0-C at 29-30:627-654). As a result, rate shock caused by the proposed change in PURA Tax allocation and collection mechanisms is ignored. IIEC and the ICC Staff have provided more balanced and comprehensive rate moderation proposals in the context of this case. Although similar to ICC Staff's rate moderation approach, IIEC's approach is superior to ICC Staff's.

The IIEC 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; the Staff approach does not.

i. Ameren Ignores the Impacts of its Proposed Rates on Large Customers' Delivery Service Costs

Ameren has proposed unprecedented levels of delivery service rate increases for its large customers. In some instances, the increase in delivery service charges is in excess of 1000%. For some customers, this translates to increases in delivery costs of over $1 million per year. Although Ameren claims to have taken into account cost impacts and rate moderation, its 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. (Stephens, IIEC Ex. 1.0-C at 3:43-50).

Ameren attempts 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. (Id. at 60-62). To wit, Ameren witness Jones claims 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 (L. Jones, Ameren 2d Rev. Ex. 16.0E at 10:175-179). However, this contradicts his alleged goalto "mitigate the rate changes to customer classes due to bill impact concerns," since the only bill Ameren sends to most large customers is for delivery service only. (L. Jones, Ameren 2d Rev. Ex. 16.0E at at 47:992-993).

Mr. Jones' focus on masking the impacts of increases in delivery service bills is understandable, as he was instructed to do so by Ameren management. Following are excerpts from an email exchange between Mr. Jones and Mr. Bob Mill of Ameren 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"
> (Stephens, IIEC Ex. 1.2, [partial Ameren response to data request IIEC 4.09] --tables omitted)

Clearly, Ameren knew the impact its proposals would have on large customers' delivery service bills, including the impacts with and without including the impact of the PURA Tax. But rather than proposing to implement any meaningful rate moderation, it 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.

ii. Costs other than delivery service costs have no bearing on delivery service rates, or the need for rate moderation

The costs of power supply, or any other energy or commodity supply, are not relevant to electric delivery service charges. The Commission no longer has authority to set the price for electric energy supply service for Ameren's customers abot 400 kW. (220 ILCS 5/16-103(c); 220 ILCS 5/16-113). Ameren does not provide the electricity supply for the vast majority of DS-4 customers, as well as many DS-3 customers. Indeed, the customer classes above 400 kW have been deemed "competitive" and Ameren is no longer required to provide fixed price energy supply service to such customers. As a result, nearly all of these customers procure power from a third-party provider. (Stephens, IIEC Ex. 1.0-C at 10:203-208)

More importantly, this is a delivery service rate case. The cost of electricity has no bearing on what the delivery service rates should be. Rather, the regulated distribution delivery service rates should be based on the prudent and used and useful investments in delivery services and a recovery of reasonable delivery service related expenses of the Ameren Companies. In fact the law requires that delivery service rates be based on the cost of ". . . owning, operating and maintaining transmission and distribution facilities." (220 ILCS 5/16-108 (b)). The electricity commodity costs paid to other entities are no more relevant to the reasonableness of Ameren's delivery service rates than would be the cost of natural gas, the cost of gasoline, the cost of food, the cost of labor, or any other cost faced by Ameren's customers, as part of their cost of doing business. By analogy, Ameren's position is akin to basing the reasonableness of U.S. postage delivery rates on the value, or lack thereof, of the contents inside the envelopes. (*Id.* at 10:209-219). By way of similar analogy, consider the cost of a truck. If a customer was required to purchase trucks from time to time and a new truck's price were increased tenfold, that would be rate shock as it relates to the cost of the truck. It would not matter whether the truck was used to transport dirt, paper or gold bullion. The cost of the transported material would not matter either. A tenfold increase (1000% increase) is a dramatic, unprecedented (in terms of utility delivery service rates) and unacceptable level of increase. Ameren’s attempts to mask the level of the proposed increases by including the cost of the commodity purchased by the customer from a third party in its impact analysis should be rejected, and a more meaningful rate moderation proposal must be implemented. (Stephens, IIEC Ex. 5.0-C at 5:80-88).

Indeed, on cross-examination, Ameren witness Althoff agreed that neither electric generation or transmission costs, nor the cost of natural gas or gas mains have <u>any relevance</u> to the determination of Ameren's delivery service costs in this case. (Althoff, Dec. 16, Tr. 574). Just as electric commodity costs have no relevance to the delivery service costs, they have no relevance to delivery service rates, and should be given no weight in determining the need for, or the implementation of, any rate moderation proposals in this case.

iii. Ameren has made a conscious effort to reduce residential rates at the expense of large customers

Ameren’s motives for not proposing a meaningful rate moderation proposal are clear. The customers most harmed by Ameren’s rate increase are large industrial customers. (See, Stephens, IIEC Ex. 1.0-C at 5-9:Tables 1-3). This was intended by Ameren, whose focus in the case, and strategy for proceeding, was 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 might also mute the impact of the revenue shift from residential customers.

IIEC witness Stephens provided for the record evidence of correspondence between Ameren President Scott Cisel and Ameren witnesses Jones and Mill, indicating the need to protect residential customers. In internal e-mail correspondence, Mr. Cisel highlighted Ameren's perception and strategy for the current rate case. In e-mails dated May 25, 2009, 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, <u>residential and small businesses are lightning rods</u>."
- "I want to better understand the proposed rate changes on residential customers and small businesses and <u>how they will play on 'Main Street'</u>. Good rate design based on the data is important; <u>however if the design causes major public unrest, we will have difficulty in achieving our desired success</u>. 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." (Stephens, IIEC Ex. 1.0-C at 14-15:311-326) (emphasis added).

In addition, in an email dated the following day, May 26, 2009, Ameren witness Bob Mill observes, "Scott very concerned re optics and outcry from small customers." (Stephens, IIEC Ex. 1.0-C at 14-15:326-328).

Thus Ameren'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. The Commission must 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 Public Utilities Act. (220 ILCS 5/1-102(d)). Stable rates, that avoid rate shock, are a necessity for all customer classes and subclasses. IIEC's proposed rate moderation approach should be adopted in this case. It applies equally to all customer classes and subclasses and provides meaningful protections.

iv. IIEC's proposed Rate Moderation Approach

IIEC originally proposed a rate moderation approach that limits the increase to any subclass's revenues to 25 percentage points above the average change in rates of the respective Ameren Companies' overall increase. However, as mentioned in Section VI. C. a., *supra*, IIEC has grave concerns about the overall validity of Ameren's electric cost of service studies in this case, due to problems which first surfaced in the surrebuttal and hearings phases of the case. Because of this, IIEC cannot support Ameren's cost of service studies for the purposes of revenue allocation or rate setting in this case. If the Commission is left without a valid measure of class and subclass cost of service, it has no basis for shifting revenue responsibility between classes and should implement any increases or decreases to the rates of the Ameren Companies on an across the board basis.

An across-the-board rate allocation would 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 of the respective Ameren Company. Thus, the 25 percentage points above the average increase proposal of IIEC, and the 150 percent of the average increase proposal of Staff are automatically met. (*See*, Lazare, Staff Ex. 7.0 at 19:424-427). This approach would also meet the Commission's goal to avoid rate shock and ease rate impacts expressed in Docket 07-0858, et al, as mentioned, *supra*:

> 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*. … [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.
> (Illinois Power Company, d/b/a AmerenIP, et al., ICC Dkt. 07-0585, et al., (Cons.), Order, Sept. 24, 2009 at 280) (emphasis added).

As noted previously IIEC originally proposed a rate moderation approach that limited the increase to any subclass's revenues to 25 percentage points above the average change in rates of the respective Ameren Companies' overall increase. IIEC now recommends this approach as an alternative, should be the Commission not adopt the across the board approach discussed above. Under this alternative approach, if (for example) AmerenIP is granted a 10% overall revenue increase in this case, no customer sub-class would receive an increase in its revenues of greater than 35% (10% + 25%). Because of the huge increases that Ameren's proposals produce for sub-classes within the DS-4 rate class, the sub-class revenue allocations should include the impact the PURA Tax. (Stephens, IIEC Ex. 1.0-C at 30-31:657-668). Staff agrees that the PURA Tax impact should be considered in the rate moderation approach. (Lazare, Staff Ex. 17:370-384). Should the allocated revenues that result in this case exceed the rate moderation thresholds, the most reasonable approach to implementing this allocation would be to first spread any revenue deficiencies to other sub-classes 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 sub-classes. If all sub-classes within a delivery rate class reach the maximum of 25% above the system average increase, then it will be necessary to spread any remaining revenue shortfall among the other sub-classes, again on a proportional basis. (*Id.* at 31:669-679). In rebuttal testimony, Mr. Stephens indicated 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. (Stephens, IIEC Ex. 5.0-C at 20-21:414-433; *see also*, Lazare, Staff Ex. 17.0 at 19-20:422-440).

v. Rate Moderation Must Occur at the Subclass Level to be Effective

Should the Commission determine that revenue allocation and rate design should not be accomplished on an across-the-board basis, it should be moderated in accordance with IIEC's recommendation. The main difference between IIEC's method and Staff's is that Staff's protection is implemented at the full rate class level, perhaps inadvertently, while IIEC's is implemented at the subclass level. As Mr. Stephens stated in rebuttal testimony:

> [Mr. Lazare's] approach does not seek to moderate the impacts at the sub class level, instead applying the constraint criterion (i.e., the cap) only at the full class level. As I explained in my direct testimony, it is important to apply the constraint at the sub-class level because there can be, and are in this case, dramatically different results for sub classes within a class. For a revenue increase moderation method to provide meaningful protection to all customers, the constraint criteria must apply at the sub class level. (Stephens, IIEC Ex. 5.0-C at 20-21:418-427).

It is clear that Staff understood that <u>the actual bills that customers must pay</u> are the basis for determining whether rate shock occurs, and should be the basis for a rate moderation plan. (See, Lazare, Staff Ex. 7.0 at 17:376-380). The bills the subclasses must pay under the Ameren proposed increase in this case are dramatically different, even within the same rate class. The increases in delivery charges vary for the DS-4 class from 24% to 1270% in AmerenCIPS, 20% to 760% on AmerenIP, and from 35% to 541% on AmerenCILCO. (*see*, Stephens, IIEC Ex. 1.0-C at 7: Table 2). Obviously, 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 sub-class to which it belongs (e.g., DS-4 100+ kV). (Stephens, IIEC Ex. 5.0-C at 21:444-446).

Furthermore, the reason customers are placed into rate classes is because their demands are assumed to have a similar effect on system costs. (Lazare, Staff Ex. 7.0 at 36:822-824). Within a particular rate class, such as DS-4, the demands of the customers with supply voltages at 100+ kV are dramatically different from those at High Voltage (15 kV to 100 kV) and at primary voltage or lower. This is demonstrated in Ameren's cost of service study results and is amplified in IIEC's cost of service study results, as indicated by IIEC witness Stowe. (Stephens, IIEC Ex. 5.0-C at 22:451-455; *see*, Stowe, IIEC Ex. 4.0 at 6-7:114 – 126, IIEC Ex. 4.2, and IIEC 8.0C 6:129-147).

Given the dramatic differences in the rate impacts within customer classes and in the cost imposed by customers taking service at different voltages, and in the delivery rates for those customers, in order for a rate moderation plan to have any meaningful effect, it must be applied at the subclass level in this docket.

vi. Ameren's and Staff's Recovery Proposal for PURA Tax Impedes Rate Moderation

Ameren and Staff propose that the PURA Tax recovery be done as a separate line item on a customer's bill. IIEC opposes this approach as indicated in Section VII.C.2.c. of this brief. However, this approach will complicate the implementation of Staff's (or IIEC's) rate moderation proposal. It will be impossible to apply Mr. Lazare's rate moderation proposal and simultaneously collect an equal PURA Tax per kWh charge as a separate line item on the bill. This is because the PURA Tax has such a dramatic effect on the overall delivery service bills of some customer classes and sub-classes (See Stephens, IIEC Ex. 1.0-C at 5:Table 1- - showing class increases of about 60% for DS-4 customers and 7: Table 2 --showing increases ranging from 78% to 131% for DS-4 High Voltage customers and 541% to 1270% 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. This is obviously an illogical result. (Stephens IIEC Ex. 5.0-C at 22:469-472). This point is agreed to by Ameren witness Jones, although he offered no solution to the problem that can maintain a meaningful rate moderation approach. (*See*, L. Jones, Ameren Ex. 55.0 at 7:147-154, L. Jones Dec 14, Tr. 109-110).

As a result, Ameren's and Staff's PURA Tax recovery approaches are incompatible with meaningful rate moderation. Of the two factors, adequate rate moderation is far more important than implementing new line item on a bill associated with a tax that is already being collected in base rates. (L. Jones, Dec 14, Tr. 108-109) Therefore, in order to comply with IIEC's, or Staff's, rate moderation proposal, the Commission must reject Ameren's and Staff's proposal to collect the PURA Tax charges on a cents per kWh basis as a separate line item and instead, maintain the current recovery of the costs through base rates, as IIEC recommends in Section VII.C.2.c. of this brief.

b. Overall Rate Design

As addressed in Sections VII.C.2. a, b, and c of this brief, IIEC opposes Ameren's proposed collection of PURA Taxes through a new line item charge on the customers' bills, the combination of the DS-3 and DS-4 classes for distribution delivery charges, and the failure to allow for combined billing for multiple meters on the same or adjacent premises. Other than these objections, IIEC does not oppose the basic rate structure and design used by Ameren, which are mostly consistent with prior rate determinations.

In this Section of its brief, IIEC addresses the issue of how to implement rates based on revenue requirement levels different from those used by Ameren or other parties in the applicable cost of service studies.

In the event that the revenue requirement approved is less than requested by Ameren (and thus modeled in its cost of service studies), Staff recommends that its proposed charges for retail customers, based on Staff's cost allocation and rate design proposals, be reduced on an equal percentage (across-the-board) basis to conform to the revenue requirement adopted by the Commission at the end of this proceeding. (Lazare, Staff Ex. 7.0 at 41:934-938; Lazare, Staff Ex. 21.0 at 20-21:453-459). Ameren proposes to start with its own proposed rates, based on its cost of service, revenue allocation and rate design proposals. Ameren then proposes to maintain uniform Meter, Customer, Transformation and Reactive Demand Charges for the classes, as applicable. The Distribution Delivery Charge is proposed to "float" to recover the remaining revenue requirement targeted for each class. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 15-16:292-298; L. Jones, Ameren 2d Rev. Ex. 40.0 at 15:313-317). Ameren and Staff primarily disagree in testimony as to whether to maintain uniform Meter, Customer, Transformation and Reactive Demand Charges.

The problem with both Staff's and Ameren's approach is that they begin with Ameren's flawed cost of service studies, which are used to develop class revenue allocations under both of their proposals. 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 Ameren, 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, they result in the same objectionable revenue shifts between classes as addressed by IIEC in other parts of this brief. However, if one starts with *current* rates and adjusts rates upward on an across-the-board basis to meet the utility revenue requirements, then there would be minimal or no cost shifting between classes.

An unusual situation is created in this case by the fact that Ameren altered its previously approved cost of service studies in major and erroneous ways, as described in Section VI.C.1., above. Correction of these errors would have no effect on final rates unless the studies are re-run with the corrections made and revenue allocation determinations are based thereon. In addition, the cost study would need to be modified to reflect the Commission's decisions on certain revenue requirement issues such as rate base, rate of return, etc.

For example, Ameren witness Althoff agreed in hearing that she should not have used new allocation factors for electric Station Equipment, FERC Account 362. (Althoff, Dec 16, Tr. 570-571). Correction of this error would affect the class and subclass costs in the cost studies. Additionally, she admitted that her cost of service studies do not reflect Ameren's surrebuttal position on PURA Tax, and that removal of $4 million PURA Tax overcollection in the cost study would shift costs among customer classes, since the energy allocator used by Ameren for PURA Tax in this case is significantly different from the rest of the utility cost items. (Althoff, Dec 16, Tr. 578-580). Correction of these errors, along with other errors determined by the Commission in this case, will have *no effect* on the resulting rates charged to customers, unless the cost studies are corrected and re-run.

Under the circumstances, if the Commission accepts the use of Ameren's cost of service studies 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, then it should order Ameren to re-run its cost of service studies and determine class and subclass revenue allocations in accordance with the Commission's findings in this case. This would provide a much sounder basis for the final rate designs. In that event, IIEC supports 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. However, if the rerun cost studies also reflect the final approved utility revenue requirements, no downward scaling would be needed.

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

As mentioned previously, ICC Staff proposed, and Ameren agreed, to recover the PURA Tax charges from customers as energy charges, creating a new and separate line item on DS-3 and DS-4 customers' bills, as an alternative to Ameren's proposed recovery through its Tax Additions rider. (See, Lazare, Staff Ex. 7.0 at 11-12:253-260; see also, L. Jones, Ameren 2d Rev. Ex. 40.0 at 3:58-67). IIEC opposes this rate design approach for several reasons.

First, it is inconsistent with the cost allocation method in present Ameren rates, which IIEC recommends be retained, as discussed in Section VI.C.1.d. Collection of this cost item on an energy basis, through an equal charge to all customers, would thwart the goal of letting rates reflect cost-causation for an item caused by historical plant in service, rather than energy.

Second, as IIEC witness Stephens explained, the PURA Tax is only one of many hundreds of individual costs that Ameren incurs and models in its cost of service study. While the amount of the PURA Tax represents a substantial expense to Ameren, it is far from being the largest of

Ameren's expenses. There is no need for Ameren to collect for each element of its costs as a separate line item on a customer's bill. There is no compelling reason to recover this cost through a separate line item on a bill, when the cost can be (and has been under current rates) allocated to customers and charged under the standard distribution delivery charges. (Stephens, IIEC Ex. 5.0-C at 16:312-319).

Third, although Ameren claims that one other Illinois utility allocates the cost of PURA Tax on an energy basis, there is no evidence in the record that <u>any</u> Illinois utility has ever collected for PURA Tax as a separate energy charge or separate line item on the bill.

Fourth and finally, as discussed in Section VII.C.2.a of this brief, the unrebutted evidence in this case is that collection of the PURA Tax as a separate line item energy charge on the bill directly conflicts with Staff's and IIEC's rate moderation approach. As IIEC explains therein, rate moderation and avoidance of rate shock is an overarching goal of proper ratemaking and in the event of a conflict with a relatively minor rate design issue, such as we have here, must take precedent. Therefore, the PURA Tax should be recovered in base rates.

Nonetheless, should the Commission determine that Ameren's and Staff's unprecedented rate design proposal for recovery of PURA Tax through a separate energy charge on customers' bills should be approved, this essentially mandates approval of IIEC's alternative allocation method for PURA Tax, discussed in Section VI.C.1.d., above. Under IIEC's alternative method, the majority of the tax, i.e. the 1997 PURA Tax (84% on average), would be recovered through base rates and allocated on the traditional plant in service basis. Only the incremental, Post 1997 PURA Tax would be allocated on an energy basis. This second portion, which would be only 16% of the total tax (on average), could potentially be recovered on a separate line item basis, without majorly disrupting the overarching rate moderation goals. However, the record is not informed on the feasibility of this result for any of the particular Ameren Companies. Therefore, the safer course for the Commission is to maintain the traditional recovery through base rates, as advocated by IIEC.

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

Ameren proposes to design rates to combine demand-related costs for DS-3 and DS-4 rate classes and divide the total demand-related costs by the combined DS-3 and DS-4 voltage differentiated demands. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 38-41:786-852). IIEC and the Staff oppose this rate design approach. (Stephens, IIEC Ex. 1.0-C at 32:691-696; Lazare, Staff Ex. 7.0 at 34-35:776-793). The Company's proposal has the effect of combining the DS-3 and DS-4 rate classes for cost allocation purposes. (Stephens, IIEC Ex. 1.0-C at 32:691-693). The Company'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. However, Ameren's approach to rate design treats DS-3 and DS-4 as a single rate class. (Lazare, Staff Ex. 7.0 at 36:820-825). The Company's approach also obscures the level of costs imposed by members of the classes. (Stephens, IIEC Ex. 1.0-C at 32:694-696). The Company's approach ignores the difference in size of DS-3 and DS-4 customers. (Lazare, Staff Ex. 7.0 at 37:831-839). Thus, the Company's approach fails to give consideration to the fact that customers with different demand sizes can impose different costs on the system. (*Id*. at 37:834-839). Finally, there is no reason to assume that DS-3 and DS-4 customers have comparable unit demand costs. (*Id*. at 36:812-816).

Under the circumstances, the Company's approach to the design of Rates DS-3 and DS-4 in this proceeding should be rejected.

g. Combined Billing and Multiple Meters

IIEC proposes a modification to Ameren'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 Ameren or having the benefit of tariff provisions permitting same prior to January 2, 2007. (Stephens, IIEC Ex. 1.0-C at 33-34:710-716). AmerenIP previously permitted such combined billing. (*Id*.).

This current Ameren policy has several implications. First, it creates a larger number of Ameren customer accounts than are necessary and increases Ameren's customer charge revenue. It also reduces the beneficial impact of diversity in separately metered loads of a single customer in a single location on the Distribution Delivery Charge.

Second, this practice effectively creates a barrier to the development of combined heat and power ("CHP") installations under certain circumstances. 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 or cogeneration plant as a separate account from the remainder of the customer's load served by the CHP facility. (Stephens, IIEC Ex. 1.0-C at 34:725-731). Such a customer would not be able to enjoy the benefit of using the output of its CHP plant or cogeneration unit to reduce the amount of electricity delivered to other production facilities in the same plant, but on adjacent premises. Furthermore, to the extent the power generated by the CHP or cogeneration unit is cheaper than power available in the market, the owner would not be able to replace the more expensive power with the cheaper cogeneration or CHP power at his adjacent facilities. (*Id*. at 34:730-734).

The Company's policy also becomes a barrier to cogeneration and CHP development in the presence of proposals to collect the PURA Tax through a cents per kWh charge as a separate line item on the customer's bill (as proposed by the Staff) or through a cents per kWh rider (as originally proposed by the Company). 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 cogeneration or CHP plant. (*Id*. at 34-35:737-739). If the generator output is not included within the same account as the plant load, it would mean the customer pays 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.

Ameren has argued that CHP units are developed within its service territories in spite of the existence of its current policy. The fact that some units have been developed does not address the fundamental problem with Ameren's policy, which will discourage CHP units within its service territories on a going-forward basis, under the circumstances described above. The fact that customers may have to spend significant sums to reconfigure their electrical distribution systems to accommodate a new CHP plant and avoid the problems described above, is not a satisfactory solution to the problem. Customers of this kind should not be forced to expend large sums of capital on reconfiguring electrical distribution system 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 Ameren's tariffs will accommodate the construction of the CHP unit without such expenditures.

Overall, Ameren's current policy has the effect of discouraging CHP installations and cogeneration installations in the circumstances described. CHP facilities are encouraged under Illinois law. (*See*, 220 ILCS 5/16-115D(h)). Under the circumstances, Ameren should be directed to modify its *Standards and Qualifications for Electric Service* to provide for combined billing for customers who have installed CHP generating plants on their plant sites or on sites adjacent to their plant consistent with the prior AmerenIP policy.

h. Rate Limiter/Cost Based Seasonal Rates

Ameren has proposed the extension of a rate limiter for grain drying customers. Absent the limiter, these customers face a class average increase of around 20%, according to Ameren. (*See*, L. Jones, Ameren 2d Rev. Ex. 16.0E at 35:726-728). The Ameren proposal provides bill relief to seasonal customers. (L. Jones, Ameren 2d Rev. Ex. 16.0E at 43:893-895). The Ameren proposal is supported by the testimony of the Grain and Feed Association (the "Association"). The Association suggests that in the absence of the limiter, the delivery service rate increases for grain drying customers could be as high as 42%. (Adkisson, GFA Ex. 1.0 at 3:48).   Staff recognizes that the purpose of the limiter was to limit delivery service increases to certain customers. (Lazare, Staff Ex. 7.0 at 36:865-867). The limiter insures that delivery service costs on a per kWh basis do not rise above a fixed amount. (*Id.*).

IIEC does not oppose the continuation of the limiter in this case. It has proposed rate moderation/mitigation measures of its own.

However, Ameren's position on the rate limiter in this case, and its response to delivery service rate increases as high as 42% for certain customers, must be contrasted with its position with regard to increases in delivery service rates as large as 1000% for some of its largest customers. (*See*, Stephens, IIEC Ex. 1.0-C at 3:44-45; *See also*, L. Jones, Ameren Ex. 40.2). The disconnect between Ameren's position on the rate limiter and its attempts to justify unprecedented rate increases as high as 1000% 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 the Ameren proposal for extension of the rate limiter for grain drying customers, and if it does, IIEC would not object, the Commission should also give favorable consideration to any reasonable recommendation to reduce the level of the rate increase requested by Ameren for all customers, and to the specific recommendations of IIEC on appropriate cost allocation and rate mitigation measures in this case. The approval of rates proposed by Ameren in this case, which will increase delivery service costs for Ameren's large customers by as much as 1000% (and millions of dollars), is beyond the boundaries of reasonableness under any measure. The Commission should treat accordingly Ameren's proposal to adopt rates in this proceeding that will have that effect and produce unprecedented increases of that magnitude.

VIII. CONCLUSION

WHEREFORE, for the reasons stated herein, IIEC recommends that its positions be adopted by the Commission.

DATED this 15th day of January, 2010.

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