STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS LIGHT COMPANY d/b/a AmerenCILCO, Proposed general increase in rates for delivery service.	)))))	Docket No. 06-0070
CENTRAL ILLINOIS PUBLIC SERVICE COMPANY d/b/a AmerenCIPS, Proposed general increase in rates for delivery service.	)))))	Docket No. 06-0071
ILLINOIS POWER COMPANY d/b/a AmerenIP, Proposed general increase in rates for delivery service.	))))	Docket No. 06-0072 (consol.)

<u>INITIAL POST-HEARING BRIEF OF THE AMEREN COMPANIES</u>

August 23, 2006

TABLE OF CONTENTS

Page

Table of Contents

I. Rate Base 1

A. Summary of Uncontested/Settled Issues 1

B. Plant Additions 1

C. Pro forma Plant Additions 1

D. G&I Plant 1

1. Functionalization of Plant 1

2. Plant Transfer 1

3. G&I Plant Amortization 1

E. Reallocation of Depreciation Reserve 1

F. OPEB Liability 1

1. Unfunded OPEB 1

2. ADIT Treatment 1

G. Cash Working Capital 1

1. Lead/lag methodology 1

2. Interest Expense Lead 1

3. Capitalized Payroll in CWC Requirements 1

4. Expense levels to which cash working capital factors are applied 1

H. Other 1

II. Operating Expenses and Revenues 1

A. Summary of Uncontested/Settled Issues 1

B. Vegetation Management/Tree Trimming 1

C. Injuries and Damages Expense 1

D. Rate Case Expense 1

1. Delivery Services 1

2. Post-2006 Basic Generation Services 1

3. Depreciation Study 2

E. A&G Expenses 2

1. Functionalization 2

2. Incentive Compensation 2

TABLE OF CONTENTS
(continued)

Page

3. Pension and OPEB Expense 2
4. Major Medical 2
5. Other A&G 2

F. Effect of Ameren Ownership on Illinois Power Expenses 2

G. Other 2

III. Rate of Return 2

A. Summary of Uncontested/Settled Issues 2

B. Capital Structure 2

1. Capital Structure Measurement Period 2
2. Imputed Capital Structures 2
3. CILCO $4.64 Preferred Stock Expense 2

C. Measurement date of Short-Term and Variable Interest Rates 2

D. Cost of Illinois Power TFTNs 2

E. Cost of Equity 2

F. Other 2

G. Recommended Rate of Return on Rate Base 2

IV. Rate Design 2

A. Summary of Uncontested/Settled Issues 2

B. Customer Class Issues 2

C. Cost of Service Issues 3

1. Segregation and accounting for delivery service and generation-related uncollectible expenses 3
2. Development of Meter Costs v. Customer Costs 3

D. Inter-Class Allocation Issues 3

1. Allocation methodology 3
2. Minimum Distribution System Study 3

E. Rider QF 3

F. Supply Procurement Adjustment 3

1. Recovery of supply-related costs 3
2. Amount of supply-related costs 3

TABLE OF CONTENTS
(continued)

Page

3. SPA tracking trhough the Market Value Adjustment Factor 3

G. Line Extension Refunds 3

H. Residential RTP Program 3

I. Other 3

V. Miscellaneous Services Issues 3

A. Line and Service Extensions 3

B. Metering Services 3

C. Vegetation Management/Tree Trimming 3

D. Other 3

VI. Responses to Commissioners' Questions 3

Page

Dated: August 23, 2006

Respectfully submitted,

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d/b/a AmerenCILCO

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COMPANY d/b/a AmerenCIPS

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PROOF OF SERVICE

I, Laura M. Earl, certify that on August 23, 2006, I served a copy of the foregoing Response by electronic mail to the individuals on the Commission's Service List for this Docket.

By: /s/ Laura M. Earl
Attorney for the Ameren Companies

I. RATE BASE

A. Summary of Uncontested/Settled Issues

The Ameren Companies will provide a summary of all uncontested and settled issues in their proposed order, which will be filed with their reply brief.

B. Plant Additions

The Ameren Companies have provided ample support for costs related to plant additions, and should be allowed to recover those expenses in rates. These additions are real and tangible, and used and useful to ratepayers. Staff has not objected to any of the Ameren Companies' plant addition costs as being unreasonable or unnecessary. Instead, Staff's proposed disallowances are related solely to disputes over documentation of the Ameren Companies' reasonably incurred costs.

During the months of January and February, 2006, ICC Staff conducted a thorough field work audit at the Ameren Companies. (*See* Respondents' Ex. 36.0, p. 33 and Respondents' Ex. 16.0, p. 32.) Ms. Ebrey testified at hearing that, during her field work audit and in the weeks following her field work, she was provided with a detailed list of the Ameren Companies' costs related to plant addition projects. (Tr. at 554, lines 6-12.) Presumably, Staff conducted a comprehensive review of the Ameren Companies' accounting practices during their field work. Following this review, Ms. Ebrey testified that she did not have any reason to believe that the cost detail for the plant addition projects did not represent actual costs on the Ameren Companies' books. (Tr. at 555, lines 8-13.)

Nonetheless, in Staff's rebuttal testimony, Staff proposes certain adjustments to the Ameren Companies' level of plant additions, based upon claims of inadequate

documentation. (Staff Ex. 13.0, pp. 17-22) While Ms. Ebrey accepted some of the additional documentation provided in Company rebuttal, she did not accept various other documents as adequately supporting the underlying plant additions recorded on the books of the Ameren Companies.

Staff's rebuttal testimony contains certain errors with respect to disallowances for recovery of plant additions. (Respondents' Ex. 36.0, pp. 36-41.) Specifically, in her rebuttal testimony, Ms. Ebrey (1) made certain mathematical errors in summing invoice costs and schedule presentation, (2) did not accept contractual documentation as adequate support for certain project costs, and (3) erroneously continued to apply her adjustment percentage to all gross plant additions without regard to whether such additions are in the Ameren Companies requested level of utility plant in service. These errors are described in further detail, by utility, below.

1. AmerenCILCO

The Ameren Companies provided three invoices in CILCO Ex. 16.14-WO 3648.pdf that sum to $75,681.13, for the plant additions work order numbered 3648. This amount was listed as supporting documentation in Company rebuttal, as shown on Exhibit 16.14, Schedule 1, Page 3 of 3, line 17.

In Staff's proposed adjustment to this schedule, Staff has recognized additional support for all but $15,299.35 of this total. The $15,299.35 appears to be a mathematical error. Staff was silent on this apparent discrepancy in rebuttal, and none of the three invoices provided total to the amount in question. Therefore, $15,299.35 should be considered a supported amount, as reflected on Exhibit 36.10, Schedule 1, Page 3 of 3, line 17.

2. AmerenCIPS

AmerenCIPS' work order 9915 and work order 11983 concern costs related to Windows NT Conversion and Alton HQTRS renovation, respectively. Staff witness Ebrey disallowed a portion of the costs associated with these work orders because the support provided was from internal company purchase orders. (Staff Ex. 13.0, p. 19, lines 370-373.) However, a review of these documents shows that the purchase orders provided in support of the disallowed costs are actual contracts with the vendors. Both the purchase order provided in support of costs incurred under work order 9915 and the purchase order provided in support of costs incurred under work order 11983 identify themselves as contracts, and are provided on Exhibits 36.11 and 36.12, respectively. . These purchase orders represent blanket orders and define pricing and terms of the underlying agreement of work to be performed, thus providing direct support for the costs in question. The total amount supported by these contracts is $501,868.42 for work order 9915 and $6,624.30 for work order 11983, and is provided on Exhibits 36.11 and 36.12, respectively.

Ameren Companies' witness Ron Stafford testified that Staff witness Ebrey asked for third-party support (contracts, invoices, etc.) for nine work orders/projects entirely independent of the underlying work orders that are the subject of her Plant Additions adjustment. Additionally, the Commission has accepted contractual documentation as support for plant additions in the past. (Respondents' Ex. 36.0, p. 39, lines 873-874.) The minimum filing requirements for electric distribution rates also expressly provide that pro forma adjustments to the test year "shall be supported by actual expenditures, written contracts, purchase orders, job orders, invoices or other evidence of reasonable certainty." (*Id.*) Thus, the contracts provided in

Respondents' Exhibit 16.14 supply ample documentation to support AmerenCIPS' reasonably incurred costs for these projects.

3. AmerenIP

Mr. Stafford testified that, for work order 25438, full support for three large invoices were provided on IP Ex. 16.14-WO 25438 prt 1.pdf on page two, IP Ex. 16.14-WO 25438 prt 5.pdf on page one, and IP Ex. 16.14-WO 25438 prt 10.pdf on page one, respectively with additional supporting documents located on these pdf files behind the summary invoice. Adding these three invoices sums to the $323,857.73 total that was identified as supported on Exhibit 16.14, Schedule 3, Page 3 of 3, column (E), line 36. There appears to be a mathematical error in Staff's calculation of these amounts. The Commission should approve the portion of the total not reflected by Staff, which has been added back in Respondents' Exhibit 36.9, Schedule 3, Page 3 of 3, column (E), line 36. (Resp. Ex. 36.0, pp. 39-40.)

4. Application of Adjustment Percentage

In rebuttal and surrebuttal, Mr. Stafford testified that Ms. Ebrey has used Plant Additions as reported on Company Schedule B-5 in her calculation of the Plant Additions adjustment reflected on ICC Staff Exhibit 13.0, Schedule 13.02. (Resp. Ex. 16.0, pp. 34-35; Resp. Ex. 36.0, pp. 40-41.) Ms. Ebrey has applied her adjustment percentage to the sum of 2001-2004 Plant Additions to determine the "Staff Adjustment to Utility Plant in Service."

To the extent Plant Additions included in her calculation are not in the Ameren Companies' requested level of gross Utility Plant in Service, Ms. Ebrey's calculation has the effect of reducing Utility Plant in Service for a given asset or group of assets below the level

included in the Ameren Companies' proposed Rate Base, and in turn results in a negative balance in Utility Plant for a given asset.

As stated in Mr. Stafford's rebuttal and surrebuttal testimony, certain Intangible Plant Additions recorded in prior years and included in Ms. Ebrey's calculation were retired or transferred, and are not in the Ameren Companies' requested level Utility Plant in Service in these proceedings. In response to Ameren Data Request 14.12, Ms. Ebrey stated that she "is not aware of any rate cases where Staff has proposed that a regulated utility be authorized a negative balance of gross utility plant in service for any account or for any functional plant group." (Resp. Ex. 36.0, pp. 40-41.)

As shown in Respondents' Exhibit 36.13, Staff's adjustment in this case results in negative Utility Plant in Service in both Account 303 specifically and for the entire functional group of Intangible Plant in Service for both AmerenCILCO and AmerenCIPS. Therefore, the Commission should approve the Ameren Companies' corrected adjustment, to exclude from 2001-2004 Plant Additions the identified Intangible Plant assets not included in the Ameren Companies' requested level of gross Utility Plant in Service.

C. Pro forma Plant Additions

Staff witness Ms. Theresa Ebrey has proposed disallowing a portion of the costs related to the project to integrate IP into Ameren's Customer Service System. At the time of filing, the Ameren Companies requested pro forma cost recovery for this project at an estimated $11.939 million. Actual costs for this project are over $12 million, and the underlying assets are used and useful in providing service to customers. (Respondents' Ex. 16.0, p. 30; Ex. 16.13.) However, to limit the number of issues surrounding this project, the Ameren Companies agreed

in rebuttal testimony to reduce cost recovery on this project to $12.131 million, the level of cost support previously provided to Staff during the field work audit on January 30, 2006.

Regardless, Staff has proposed, inexplicably, a disallowance for this project based on its calculation of unsupported *actual* costs, subtracted from the Ameren Companies' original *estimate* of the project's costs. This is unsound.

At hearing, Ms. Ebrey confirmed that Staff's proposed disallowance for this project was calculated based on a list of *actual* company costs provided during Staff's field work audit in January. (Tr. at p. 552, lines 10-19.) That list has been entered into evidence as Respondent's Exhibit 36.7. Ms. Ebrey testified that, in reaching her proposed disallowance, she determined which of the Ameren Companies' list of actual costs were not supported by invoice. (Tr. at p. 553, lines 5-8.) The sum of those costs, multiplied by the electric distribution allocation factor, are identified as unsupported on Line 3, Schedule 2.03, ICC Staff Exhibit 2.0. But to reach the proposed adjustment on Line 10, Ms. Ebrey subtracted this sum of unsupported *actual* costs from the Ameren Companies' original cost *estimate* for the project, $11,939 stated in $000. (Line 4, Schedule 2.03, ICC Staff Exhibit 2.0; Tr. at p. 551, lines 15-18.)

The Ameren Companies believe that they have provided sufficient justification and support for full recovery of the actual costs in the amount of $12.131 million. Staff has provided no reason why the Ameren Companies' cost detail for the project cannot be relied upon – in fact, Ms. Ebrey testified that she relied upon it herself in determining "unsupported costs." (Tr. at p. 552, lines13-22, p. 553, lines 1-8.) Staff's proposed adjustment should be disregarded.

However, if Staff's proposed adjustment is accepted, common sense and appropriate accounting procedures dictate that Staff's "unsupported" actual cost total, derived from the Ameren Companies' actual cost detail, should be subtracted from the total amount of the Companies' actual costs, not the estimate.

D. G&I Plant

1. Functionalization of Plant

2. Plant Transfer

3. G&I Plant Amortization

The Ameren Companies address all of the above topics below.

The most significant contested issue (from a revenue requirements perspective) involves the functionalization of general and intangible ("G&I") plant and associated expenses.

General plant consists of assets such as land, buildings and structures, office furniture and equipment, transportation equipment, stores equipment, tools, shop and garage equipment, laboratory equipment, power operated equipment and communication equipment. Each of these types of assets has a unique depreciable life which would be determined via a depreciation study.

Intangible plant consists primarily of software or systems that are purchased or developed for use by the Companies. For the most part, intangible plant is amortized over a short period of time (e.g., five years).

Historically, while some of the G&I plant assets were used by and benefitted more than one line of business, the assets primarily benefitted the "pipes and wires" businesses. For example, the land and structures that have been recorded as G&I plant represent discrete assets that can be identified and assigned or allocated to specific lines of business. The vast

majority of the assets in those accounts are district field facilities that house field operations personnel and have never provided support to the electric production business. Accordingly, it would be inappropriate to assign or allocate a portion of these G&I plant assets to the electric production business.

Because G&I plant can have multiple uses, the Commission must "functionalize" that plant, i.e., it must determine what portion of the plant supports a particular function. The Commission recently (very recently) again made clear that its preference is for the use of a "direct assignment" of costs, rather than the use of an allocator approach, such as the general labor allocator that it employed in the original DST rate cases. Commonwealth Edison Co., Docket No. 05-0597, Order at p. 27 (July 26, 2006).

The Commission's decision to rely on direct assigment over the general labor allocator is a sound one. The labor allocator is easy to apply, but can produce anomolous results. The allocator uses labor expense to allocate const to different functions, by using a ratio, the denominator of which is the total labor expense and the numerator of which is the labor expense for a particular function. Tr. at 771 (Chalfant). The labor allocator does not take into consideration the nature or use of the assets. The approach is merely a mathematical calculation to allocate the costs of assets, in aggregate, to various lines of business. For example, a vehicle used exclusively by electric crews would be directly assigned to the electric business in the ASP. Using the labor allocator, a portion of the same truck would be allocated to each line of business (i.e., electric transmission, electric distribution, and gas).

A simple example demonstrates how the labor allocator can produce unreasonable results. In the example, a company has both distribution and generation functions, with 10 employees who are paid equally. Five employees are in distribution and five are in generation.

Thus, under the labor allocator, 50% of G&I plant would be allocated to distribution and 50% would be allocated to generation. Tr. 771-72 (Chalfant).

If that company were to make additional investment in software to make distribution more efficient, the allocator produces a result that is the opposite of what we would expect. If the company installs a new software system that allows to operate the distribution system with only four employees, less G&I plant is allocated to distribution, not more. Instead of 50% (5/10) of G&I plant being allocated to distribution, only 44% (4/9) is allocated to distribution. Tr. 771-74 (Chalfant). Thus, where the company invests more in software to assist distribution, the labor allocator assigns 5/9 of the new investment to generation, and alters the allocation of existing investment by assigning more of it to generation, irrespective of what use the generation function makes of the new software.

Accordingly, the Commission's clearly stated preference for direct assignment is proper and reflects sound regulatory policy.

The Ameren Companies functionalized G&I plant in a manner precisely consistent with the Commission's policy. Based on an exhaustive review and analysis, the Companies assigned plant where they could, and used appropraite allocators where they could not.

Mr. Adams oversaw an Asset Separation Project ("ASP"). The ASP represents the results of the review of the Company's continuing property records to determine which assets should be assigned or allocated to the electric distribution business. The objective of the ASP was to determine how each asset was used and to assign the cost of the asset to the appropriate line of business according to its use. Where possible, an asset was directly assigned to a

particular line of business. If an asset supported more than one line of business, an allocator was employed to assign the cost of the asset to each line of business it supported.

The starting point for the study was a listing of each of the Company's assets. Resp. Ex. 7.0 CILCO, p. 4. Based upon a review of those assets, a preliminary determination was made as to whether the asset supported one or more lines of business. Direct assignment of assets was employed wherever possible. For example, electric production, transmission, and distribution plant, and gas plant were directly assigned to the appropriate business function. Some G&I plant assets were also directly assigned to particular lines of business. The remaining assets, which are recorded on the Company's books as either gas or electric G&I Plant, were reviewed since they may support more than one business function and thus require allocation among business units. Id.

To determine how the G&I Plant was actually used, information regarding the use of the asset was reviewed. If necessary, the users of the assets were contacted to determine which lines of business the assets support and an appropriate allocator to apply to the assets. Such employees are in the best position to have knowledge of how the assets are used and how best to allocate or assign the costs of such assets to the various lines of business. The appropriate allocators were then applied to the assets in order to assign or allocate the costs of each asset to a particular line of business. Resp. Ex. 7.0 CILCO, p. 5.

Direct assignment of G&I Plant was employed whenever possible. When direct assignment was not possible, the specific continuing property records for the particular asset were examined to determine if there was adequate information to determine a basis of allocation. If sufficient information was not available, users of the specific asset were contacted to

determine the exact use of the asset and an appropriate allocation basis. Resp. Ex. 7.0 CILCO, pp. 5-6.

In most cases, the allocators are based on readily available information such as customer counts or operation and maintenance ("O&M") expense levels. For the more generalized allocators, such as number of customers or O&M expense levels, the information needed to calculate the allocation percentages was taken directly from the Company's 2004 FERC Form 1. To develop the more specialized allocators, the organizations responsible for managing the asset were contacted to obtain insights as to the appropriate allocation of costs to the individual lines of business. Resp. Ex. 7.0 CILCO, p. 6.

The Companies submitted detailed studies of the G&I plant and the appropriate allocation and assignment of the assets to the electric transmission, electric distribution, gas and the electric generation businesses reflected on the books of the regulated companies. The Companies' ASP, supported by detailed workpapers, shows on an account-by-account basis the assets which are included in the Companies' proposed rate base in these proceedings. The ASP shows the allocator used to assign the cost of the plant to the various lines of business reflected on the books of the regulated companies and the calculation of each allocator. Resp. Ex. 37.0, pp. 4-5.

Accordingly, the Ameren Companies' functionalization of G&I plant was sound, supported by an exhaustive and reasoned analysis and consistent with clearly stated Commission policy.

Notwithstanding the clear evidence to the contrary, both the Staff and IIEC proposed adjustments to G&I plant. Notably, neither party challenged any particular element of the Companies' study. Nor did they question the prudence or used and usefulness of any specific

plant item wholly or partially included in rate base. Rather, their adjustments – while arrived at by different paths – were based on the Commission's Orders in each Company's last delivery service tariff ("DST") proceeding. As will be discussed, to adopt the position of Staff and IIEC, the Commission must conclude, despite all evidence to the contrary, either that: (i) the G&I plant assets on the utilities' books are being used by the Companies' affiliates' non-regulated generation businesses, or (ii) the assets are not being used in support of the Companies' regulated electric businesses. Neither of the propositions is correct.

The Staff challenged the Companies' G&I plant levels on two bases: first, the Staff contend that G&I plant should not be directly assigned, and second, the Staff alleged that the Companies were merely trying to refunctionalize to distribution that which the Commission allocated to generation in the DST cases.

The Staff has misunderstood the Commission's policy regarding functionalization of G&I plant. Staff witness Lazare contended that "The Commission has concluded that these costs are not conducive to a direct assignment approach and should be instead allocated on a general basis." The Commission has done no such thing. In the Order in Docket No. 01-0645, on which Mr. Lazare relied, the Commission "note[d] that while it has expressed a preference for the direct assignment of costs, that preference was subject to the condition that the costs in question are suited to direct assignment and sufficient cost data is available to make direct assignments." The Commission continued, "In the Commission's view, important considerations in assessing whether costs should be directly assigned to a specific function, or how they should be allocated among functions, are the nature of the facilities and the type and scope of activities for which they are used."

The costs at issue here are clearly capable of being directly assigned. Once the usage of the G&I plant assets is determined, the costs can be direct assigned to one or more of the lines of business. For example, if a bucket truck is used exclusively by the electric distribution business, the cost of the vehicle can be direct assigned to the electric distribution business. If the asset is used by both the electric transmission and the electric distribution business, but not the gas business, the cost can be directly assigned to the electric transmission and electric distribution businesses and allocated between the two businesses based upon its actual usage or a proxy for its usage. Resp. Ex. 37.0, p. 19.

If there were any doubt about this, the Commission's recent order in Commonwealth Edison Co. (Docket No. 05-05997) removed it:

> Further, the Commission agrees with ComEd that use of "direct assignment" of costs is the preferred approach over the general labor allocator approach. *Because determining such costs is possible*, the Commission is in agreement with ComEd that direct assignment should be used in this case. (emphasis added) (p. 27)

Staff's second basis for its adjustments is also baseless. In the DST cases, the Commission functionalized a certain amount of G&I plant to generation. Mr. Lazare claimed in this case that the "Companies are attempting to refunctionalize this plant back to the revenue requirement." This is simply incorrect. The Companies' ASP reflects the actual assets which were on the books as of December 31, 2004 and how such assets are used by the Companies to provide service to its customers. The G&I plant which has been included in the Companies' rate base in these proceedings reflect the plant that is used by the electric delivery services business. The Companies transferred the G&I plant which supported the non-regulated generation business to those businesses. Therefore, the Companies are not attempting to refunctionalize plant back to the electric distribution business but rather is accurately reflecting how the assets are used and

attempting to earn a fair return on those assets which are used by the electric distribution business from the customers which benefit from the use of such assets.

Moreover, the Companies cannot refunctionalize to generation that which is no longer there. The amount that Staff proposes to disallow is seriously overstated. For example, since Mr. Lazare relied upon G&I plant in service as of December 31, 2000 for AmerenCILCO, his proposed disallowance would include plant which has already been transferred to the non-regulated generation company (i.e., ARG), which was formed in 2003. Similarly with AmerenCIPS, Staff witness Lazare employs information as of December 31, 1999 to quantify his proposed adjustment. The non-regulated generation company AGC, which consists primarily of AmerenCIPS' former generation facilities was formed in 2000 and the assets would have been transferred from the Company's books to AGC in 2000. Resp. Ex. 37.0, p. 21.

For both AmerenCILCO and AmerenCIPS, the G&I plant which was transferred to ARG and AGC would already have been removed from the Companies' proposed rate base in these proceedings. Therefore, Staff witness Lazare is proposing to disallow plant which is not even included in rate base. Resp. Ex. 37.0, p. 21.

IP's 2000 test year used in its last DST proceeding included significant amounts of intangible plant associated with information systems which were used by the Company. Since the acquisition of IP by Ameren, many of the systems on the books of IP have been written off by Ameren. Despite the fact that the intangible plant has been written off since AmerenIP's last DST proceeding and is not included in rate base in these proceedings, Staff is proposing to disallow a portion of the intangible plant that is no longer even on the books of the Company. Resp. Ex. 37.0, pp. 21-22.

Staff's's position also fails to recognize the further amortization or depreciation of the G&I plant assets which were on the books of the Companies as of December 31, 1999 or 2000. For example, most intangible plant has an amortized life of five years. Therefore, most if not all of the intangible plant which was on the Companies' books in the last DST proceedings would be fully amortized and have a net book value of zero in these proceedings. However, Staff proposes to disallow the value of the intangible plant that was on the books of the Companies in the prior DST proceedings, even though the assets have a net value of zero in rate base of these proceedings. Resp. Ex. 37.0, p. 22.

The same would also be true with general plant. Staff witness Lazare's proposed adjustment fails to reflect the further depreciation of general plant since the last DST proceedings. Resp. Ex. 37.0, p. 22.

This is no mere tweaking of the numbers. For example, Mr. Lazare had proposed a disallowance of AmerenIP's G&I plant as of December 31, 2000 of $123,631,000.[1] Once the G&I plant as of December 31, 2000 which is no longer on the Company's books or via pro forma adjustments are removed, Staff's adjustment would be $12,037,000 instead of $123,631,000. Resp. Ex. 37.0, p. 24.

IIEC and Mr. Chalfant fare no better. Mr. Chalfant's core contention is that all G&I plant is used for all functions – including functions undertaken by the generation affiliates. IIEC (and the Staff for that matter) would have the Commission believe that the Companies' commercial office buildings in Marion, Quincy, Lincoln, Decatur, Springfield or elsewhere throughout state are used by the non-regulated generation businesses. To the contrary, these facilities house crews which are responsible for operating and maintaining the pipes and

[1] Ibid, pp. 16-17, lines 377-380.

wires businesses in these communities. These crews (and the assets that they use) do not spend portions of their time at the non-regulated generation businesses' facilities. They begin their days at the commercial offices. During the day, they are in the field constructing and maintaining the Companies' pipes and wires. At the end of the day, the crews return to the commercial office and store their equipment on the grounds overnight.

Mr. Chalfant, though enamored of the labor allocator, does not propose its use in this case. Rather, he proposes that increases in G&I plant since the prior DST cases be limited to the percentage increases in distribution plant over the same period. There are three reasons why this proposal should be rejected.

First, the test years used in the Companies' last DST proceedings are 4 to 5 years older than the test year in these proceedings. No party has challenged that calendar year 2004 is an appropriate test year for these proceedings, yet Mr. Chalfant seeks to bring outdated 4 to 5 year old data into this proceeding without regard to the applicability of the data. The Companies' operations have changed significantly over the last four years and it is not appropriate to set rates –directly or indirectly – on an outdated test year. Resp. Ex. 37.0, p. 6.

Second, there is no sound basis for this proportionality principle. Mr. Chalfant acknowledged at hearing that there is no relationship between investment in distribution assets and G&I plant. A utility need not buy a new software system when it builds a new line, and it need not build a new line when it buys a new software system. Tr. __ (Chalfant).

Lastly, the Commission pointedly rejected this very proposal in the ComEd case last month:

> Moreover the Commission finds that the IIEC's argument for limiting the increase in general and intangible costs in proportion to distribution plant costs to be insufficient and

> unsupported by the record. Although the IIEC witness advocated such a position he never identified any cogent reason for such a correlation.

Commonwealth Edison Co., Docket No. 05-0597, p. 27 (July 26, 2006)

To adopt the position of either Staff or IIEC, the Commission must conclude that, despite the evidence to the contrary, that the G&I plant assets are being used by the non-regulated generation businesses or that the assets are not being used in support of the Companies' electric transmission, electric distribution, gas or electric generation businesses which remain on the books of the regulated companies. There is no evidence in the record to support either claim, because such positions are wrong and unsupportable. The G&I plant assets included in rate base in these proceedings are being used to provide electric distribution services to the Companies' customers.

Ameren acquired Illinois Power from Dynegy effective October 1, 2004. Only the "pipes and wires" businesses and the supporting assets were acquired by Ameren. Dynegy owns the former IP fossil generation and Exelon owns the former IP nculear generation. Tr. 777 (Chalfant). For Staff's and IIEC's position to be accepted, the Commission must conclude that either:

> (1) The G&I plant which was acquired by Ameren associated with the acquisition of Illinois Power's pipes and wires businesses continue to support a generation function which is owned by Dynegy; or
>
> (2) The G&I plant which was acquired by Ameren associated with the acquisition of Illinois Power's pipes and wires businesses is not used to support AmerenIP's regulated electric businesses.

There is no evidence in this proceeding to support either position simply because neither position is true. More to the point, neither Staff witness Lazare nor IIEC witness Chalfant identifies any specific G&I plant assets to disallow. Instead each merely developed a

number and deemed that amount of G&I plant to be unrelated to the distribution business and thus unrecoverable. Resp. Ex. 37.0, pp. 7-8.

The adjustments to G&I plant and associated expenses propsed by the Staff and IIEC should be rejected.

E. Reallocation of Depreciation Reserve

The depreciation study conducted in preparation for this rate case indicates a substantial increase in depreciation rates for AmerenIP, as described further below, in subsection I.D.3. In the interest of ratepayers, as discussed below, the Ameren Companies have not recommended an increase in AmerenIP's depreciation rates at this time. However, the Ameren Companies are requesting permission to reallocate the AmerenIP depreciation reserve in order to mitigate the future impacts of changes in depreciation rates on customers. (Respondents' Ex. 16, pp. 11-13; Respondents' Ex. 36.0, pp. 15-17.) Respondents' Exhibit 36.4 represents the proposed reallocation based on year-end 2004 reserve balances, along with an illustration of the depreciation rate impact of the reallocation.

The Ameren Companies' understanding is that they could request such approval from FERC. (*Id.*) However, since a depreciation study has been conducted in conjunction with the instant proceedings, the Ameren Companies consider it to be more administratively efficient and more appropriate to request such approval from the ICC at this time.

In rebuttal, Staff witness Jones testified that she has "found nothing to indicate that reallocation of the depreciation reserve is acceptable under the rules of Generally Accepted

Accounting Principles ("GAAP"). Ameren Companies' witness Stafford testified that applicable guidance is found in the Statement of Financial Accounting Standards 71:

> While there may be other authoritative sources that provide support under GAAP, the Statement of Financial Accounting Standards ("FAS") 71: Accounting for the Effects of Certain Types of Regulation does provide guidance that can be construed as supportive of the Ameren Companies' request, given that AmerenIP is a rate-regulated utility under ICC jurisdiction. Specifically, at paragraph 51 of FAS 71, a threshold issue is addressed: "Should accounting prescribed by regulatory authorities be considered in and of itself generally accepted for purposes of financial reporting by rate-regulated enterprises?" The answer provided in paragraph 52 stated in part "…..the economic effect of regulatory decisions-not the mere existence of regulation-is the pervasive factor that determines the application of generally accepted accounting principles." In other words, actions of a regulator, such as in this case approving reallocation of the depreciation reserve, can directly impact and influence whether a rate-regulated utility is in compliance with GAAP.

(Respondents' Ex. 36.0, pp. 17-18.)

The review of AmerenIP's depreciation reserve by account and by function indicated a large disparity in the actual reserve vs. the calculated reserve conducted in preparation of the depreciation study. (*Id.* at 18.) As illustrated on Respondents' Exhibit 36.4, the reserve shortfall is predominantly in shorter-lived assets. Amortization of the reserve shortfall of shorter-lived assets occurs over a much shorter remaining life, and results in higher overall depreciation expense. (*Id.*) By reallocating the reserve, the customer impact of any reserve shortfalls on an account by account basis is mitigated. (*Id.*)

In this specific case, this reallocation of depreciation reserve has the impact of mitigating the otherwise necessary increase in depreciation expense by $17,099,000 annually, as shown on Respondents' Exhibit 36.4. (*Id.*) Because the record demonstrates that reallocation is

reasonable and will be a significant benefit to AmerenIP's customers on a going-forward basis, the Commission should approve this proposal.

F. OPEB Liability

1. Unfunded OPEB

AG witness David J. Effron and ICC Staff witness Burma Jones propose including accrued OPEB liability in rate base. As discussed below, this proposal is demonstrably incorrect, as it is based on a factual misunderstanding regarding OPEB accounting procedures and funding.

a. AG

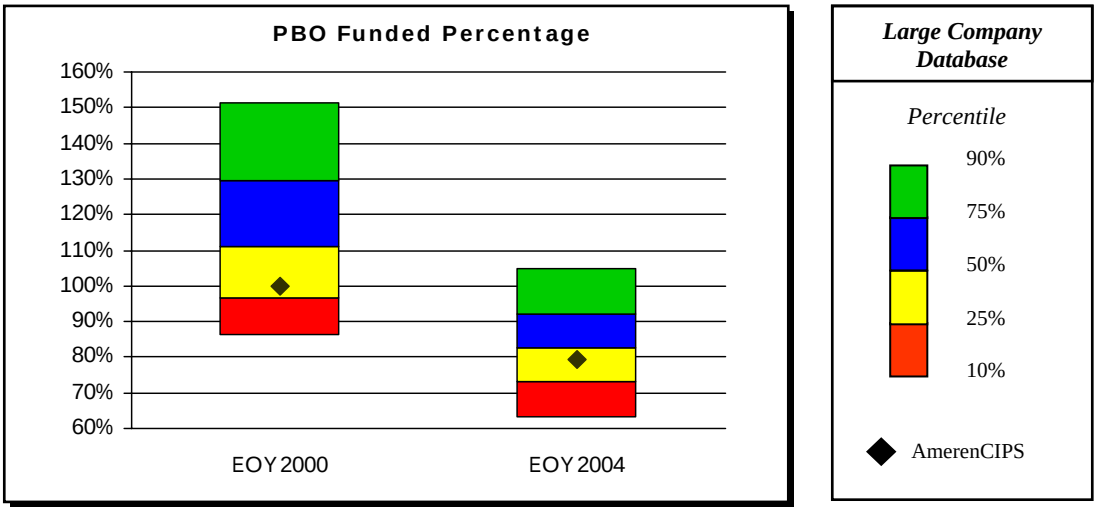
The AG's position on OPEB expenses is based on a fundamental misunderstanding or misstatement of the facts. Mr. Effron contends that ratepayers have supplied funds in excess of what the Ameren Companies have paid for OPEB, and that the excess is available to support the Company's operations. (AG Ex. 1.0, pp. 7-8.) This assumption is incorrect, and unsupported by the record evidence.

As explained in the testimony of Ameren Companies' witness C. Kenneth Vogl, pension and OPEB expenses approved in prior orders (in 1999 or 2000) were low compared to pension and OPEB expenses in the current test year, reflecting expenses for better funded plans that were generated by the high equity returns, higher interest rates, and lower medical costs during the late 1990s.

Such high equity returns did not happen in the 2000-02 period. This fact, combined with decreasing interest rates has led to a decline in the funded status of the Ameren

Companies' pension and OPEB plans. Mr. Vogl explained that this decline in funding is consistent with the experience of other companies offering pension plans, during the same time period. In other words, the decrease in the plan's funded status is largely due to factors outside of the Ameren Companies' management control.

As support for this point, the chart below shows the distribution of pension plans' funded percentages as of the end of 2000 and the end of 2004. AmerenCIPS's actual funded percentage is also shown and indicates AmerenCIPS's experience has been fairly consistent with other companies. The distribution of other companies' funded percentages shows the median pension plan funded percentage has dropped 25% – 30% over the last five years which in turn has caused the significant increases in pension expense. AmerenCIPS's funded percentage has dropped 20% over the same period. .



Mr. Vogl illustrated this point for each of the Ameren Companies in his direct testimony.

Thus, the decline in the funded status of pension plans has led to more employer contributions to pension trusts. The chart below shows that ratepayer funding has fallen far short of the overall OPEB contribution from each of the Ameren Companies:

OPEB Contribution		
	Ratepayer Contribution	Total Company Contribution
AmerenCIPS	$0.8 million/year	$41.8 million from 1999-2005 (average of $6.0 million per year)
AmerenCILCO	$2.6 million/year	$23.7 million from 2000-2005 (average of $4.0 million per year)
AmerenIP	$1.0 million/year	$22.4 million from 2002-2005 (average of $5.6 million per year)

(Respondents' Ex. 42.0, pp. 3-4.)

This chart demonstrates that, on average, over each of the past several years AmerenCIPS has spent $5.2 million more on OPEB expenses than they have received in rates ($6.0 million average annual contribution less $0.8 million received annually in rates). AmerenCILCO has annually spent $1.4 million more than they have received in rates, and AmerenIP has annually spent $4.6 million more than they have received in rates. (Respondents' Ex. 42.0, p. 4.)

In summary, the record shows that the Ameren Companies have contributed far more for OPEB than it has collected from ratepayers, even though a small accrued OPEB liability exists. Mr. Effron's assumption that this liability must represent ratepayer supplied funds is thus wrong. As Mr. Vogl explained, accrued OPEB liability is the excess of OPEB expense recorded by the Company (a non-cash expense recorded by the Company on its income statement) over the amounts the Company has actually paid for OPEB. It does not necessarily

represent ratepayer supplied funds that the Company intends to use for OPEB. There is no excess. (Respondents' Ex. 21.0, p. 8.)

On these grounds, Mr. Vogl testified that if an adjustment to rate base were to be made, he would recommend that the correct adjustment would be an increase to rate base equal to the excess of OPEB funds contributed over the amount collected in rates from ratepayers. (Respondents' Ex. 21.0, pp. 8-9.)

b. ICC Staff

Staff witness Burma Jones, however, testified on rebuttal that an adjustment reducing rate base by the amount of the accrued OPEB liability was warranted, based on the direct testimony of AG witness David Effron. Ms. Jones' testimony is incorrect for the same reasons described in subsection I.F.1.a. above.

Ms. Jones also incorrectly assumes that accrued OPEB liability has come from ratepayers, commenting that the "liability reflects a cost-free source of capital on which shareholders are not entitled to receive a return.". She further comments in lines 346-348 that "an OPEB liability reflects that the Companies have recorded more OPEB expense than they have actually paid".

As Mr. Vogl explained in his surrebuttal testimony, a cost-free source of capital on which shareholders are entitled to receive a return would represent funds collected through rates that are attributable to OPEB benefits, but ultimately not used to pay for OPEB benefits. (Respondents' Ex. 42.0, pp. 2-3.) But this is not what the accrued OPEB liability represents. As mentioned above, the accrued OPEB liability represents the excess of OPEB expense recorded

by the Company (a non-cash expense recorded by the Company on its income statement) over the amounts the Company has actually paid for OPEB. The only way that Ms. Jones' description could be accurate would be if the OPEB expense recorded by the Company were equal to the funds collected in rates attributable to OPEB benefits for every year.

This is clearly not the case, as demonstrated above. *See* subsection I.F.1.a, *supra.* The OPEB amount collected through rates is fixed for a period of time. The amount of OPEB expense recorded by the Company, however, varies from year to year and has generally increased over the past several years. (Direct Testimony of C. Kenneth Vogl, AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0.) Thus, to the extent the OPEB expense recorded by the Company differs from the amount collected through rates, the accrued OPEB liability gets farther and farther away from what Ms. Jones has described as a "cost-free source of capital on which shareholders are not entitled to a receive a return."

2. ADIT Treatment

Based on the incorrect factual assumptions regarding pension and OPEB liabilities of Staff witness Jones and AG witness Effron, described above, Staff and AG have also recommended an incorrect adjustment to OPEB-related Accumulated Deferred Income Taxes ("ADIT") in its calculation of pro forma rate base. (AG Ex. 1.0, pp. 7-8; ICC Staff Ex. 14.0, pp. 19-20.)

The Ameren Companies' direct testimony included, in error, OPEB-related ADIT in their rate base calculations. In rebuttal testimony, Mr. Stafford agreed with Mr. Effron's recommendation to treat OPEB-related ADIT consistently with the Companies' treatment of accrued OPEB liability, and thus removed OPEB-related ADIT from rate base. For the reasons

discussed in subsection I.F.1, *supra,* and the direct, rebuttal, and surrebuttal testimony of Ameren Companies' witness Mr. Vogl, OPEB-related ADIT should be removed from rate base. (Respondents' Ex. 36.0, pp. 32-33.)

G. Cash Working Capital

Cash working capital is the amount of funds required to finance the day-to-day operations of the Company. Cash working capital determinations are generally intertwined with lead-lag studies that are used to analyze the lag time between the date customers receive service and the date that customers' payments are available to the Company. This lag is offset by a lead time during which the Company receives goods and services, but pays for them at a later date. The "lead" and "lag" are both measured in days. Since the test year was a leap year, the dollar-weighted lead and lag days are then divided by 366 to determine a daily cash working capital factor ("CWC factor"). This CWC factor is then multiplied by the annual test year cash expenses to determine the amount of cash working capital required for operations. The resulting amount of cash working capital is then included as part of the Company's rate base. The test year operating expenses to which the leads and lags were applied are described in the direct testimony of Company witness Stafford.

Two broad categories of leads and lags should be considered: 1) lags associated with the collection of revenues owed to the Company ("revenue lags"); and 2) lead times associated with the payments for goods and services received by the Company ("expense leads"). A revenue lag refers to the elapsed time between the delivery of the Company's product (i.e., electricity) and its ability to use the funds received as payment for the delivery of the product. The expense lead refers to the elapsed time from when a good or service is provided to the

Company to the point in time when the Company pays for the good or service and the funds are no longer available to the Company.

Navigant Consulting, Inc. ("NCI") performed a lead-lag study by analyzing each Company's cash transactions and invoices for the twelve months ended December 31, 2004. Based on that study (with certain adjustments accepted during the case) the Ameren Companies have proposed cash working capital requirements of $754,000 for AmerenCILCO; $1.006 million for AmerenCIPS; and $285,000 for AmerenIP. Ameren Exs. 37.0, p. 50; 36.1; 36.2; 36.3. In contrast, Staff has proposed cash working capital requirements of ($1,575,000) for AmerenCILCO, ($3,470,000) for AmerenCIPS, and ($6,613,000) for AmerenIP. Staff's negative results arise for its differences with the Companies in five specific areas.

1. Lead/lag methodology

The principal difference between Staff and the Companies relates to the overall methodology used. The Companies employed a "Net Lag" methodology to determine its cash working capital requirements. Under the Net Lag approach employed by the Companies, an overall revenue lag, representing the passage of time from when the Companies provide service to its customers and the receipt of available funds from its customers for such services, is netted against the expense lead for the various expense classifications. The net of the revenue lag and expense lead are then multiplied by the expense level for each expense classification. Resp. Ex. 16.0, p. 26.

In this proceeding, Staff proposed to use a "Gross Lag" methodology to calculate the Companies' cash working capital requirements. Under the Gross Lag methodology, the

revenue lag is applied to gross revenues and non-cash items which are used to reduce the revenues. The expense leads are applied to each expense classification. Resp. Ex. 16.0, p. 26.

Thus, the primary difference between the two methodologies is the reflection of revenues in the Gross Lag methodology.

The Commission has endorsed both methods in the past, but, until this case, the Staff has argued hard for the Net Lag approach. The methodology employed by the Companies is consistent with the methodology ultimately approved by the Commission in Docket Nos. 02-0798/03-0008/03-0009 (Cons.), the prior gas rate cases of AmerenCIPS and AmerenUE-Illinois. In that case, the Staff endorsed the Net Leg approach. Resp. Ex. 16.0, p. 26. Staff witness Ebrey stated in that case that "Rather than the methodology used by the Company in the instant case, the more appropriate method of deriving a net lag is to offset the expense lead by the revenue lag for each expense area" (or the Net Lag approach). According to Staff witness Ebrey, "This methodology is consistent with the Company's description of a lead/lag study cited above as well as that utilized by AmerenUE in 2002 in Case EC-2002-1 before the Missouri Public Service Commission." Resp. Ex. 16.0, p. 27.

Staff has apparently changed its mind. In her direct testimony in this proceeding, Ms. Ebrey stated that, "as the witness addressing CWC in that (AmerenCIPS and AmerenUE) proceeding, I reviewed the CWC analysis that AmerenUE had proposed in its Missouri gas rate case. It was my opinion at that time that the net lag methodology addressed the concern I had with non-cash items being included in the CWC analysis. In addition, everything else equal, it seemed appropriate for the same methodology to be used by the Ameren Company in both its Illinois and Missouri jurisdictions for concurrent gas rate cases. " ICC Staff Ex. 2.0, p. 7. She further stated that "I believe that the methodology utilized in the CWC analysis prepared by

[NCI] in the last Illinois Power Company rate case is superior to the methodology used in Docket Nos. 02-0798/03-0008/03-0009. In particular, it better addresses my concern that the non-cash items be excluded from the CWC analysis." Id. at 8.

The explanation provided by Staff for its flip-flop on the lead-lag methodology is highly suspect. The Net Lag methodology employed by the Companies only includes revenues in the calculation to determine the revenue lag. The calculation of the revenue lag would be same whether the non-cash items were excluded from the calculation or not. Resp. Ex. 16.0, p. 28.

The Gross Lag methodology presented by Ms. Ebrey requires that the level of revenues first, be determined, and second, be adjusted for various non-cash items. Therefore, it is counterintuitive to reject a methodology that requires no determination of revenues or adjustments to revenues. It should also be noted that Ms. Ebrey utilizes the same revenue lag as was calculated by the Companies. Resp. Ex. 16.0, pp. 28-29.

In the prior Ameren proceedings in which Staff recommended a change to (and not from) the Net Lag methodology, the result was a decrease in the Companies' requested level of cash working capital. Similarly, in this proceeding Ms. Ebrey is recommending a change in methodology (from the one that she previously recommended) that, and perhaps not coincidentally, results in a reduction of the Companies' requested level of cash working capital. On its face, it appears that Staff is less concerned about the methodology used than the result achieved.

There are three reasons why the Companies adopted the Net Lag methodology to determine its CWC requirements. First, the Companies wanted to ensure consistency across all of the companies. Second, the methodology has been accepted by both state regulatory

jurisdictions in which the companies operate. Finally, most state regulatory jurisdictions have adopted the Net Lag approach to determine a company's CWC requirements. Resp. Ex. 16.0, p. 30.

The ability to adopt one methodology for both jurisdictions is expected to reduce the Company's cost of conducting such analyses. In addition, the iterative nature of the Gross Lag methodology increases the difficulty of calculating the Companies' CWC requirements. The Gross Lag CWC calculation requires modification each time any one of the following components is changed:

1. Revenues
2. Proposed increase
3. Uncollectible expenses
4. Depreciation and Amortization Expenses
5. Return on equity
6. Non-cash OPEB expenses.

The Net Lag methodology does not include revenues (except to calculate the revenue lag), so no such adjustments are necessary. The Companies' studies do not include uncollectible expenses, depreciation and amortization, return on equity or non-cash OPEB expenses, therefore, no adjustment to the Companies' methodology is required. Staff witness Ebrey's concerns with regards to the Companies' CWC methodology are unfounded. Resp. Ex. 16.0, pp. 30-31.

CWC analyses can be costly and time-consuming to conduct. Ameren has presented CWC studies in a number of rate proceedings employing the Net Lag methodology. In fact, the Net Lag methodology has been adopted by this Commission in past rate proceedings. Resp. Ex. 16.0, p. 31.

The Companies have made efforts to streamline the process (and thereby the cost) of preparing such studies. The Companies now uses statutory due dates instead of actual payment dates wherever possible so that fewer items need to be analyzed. Analysis of these items would likely increase the Companies' CWC requirements if analyzed. The Companies also calculate leads and lags for all of the regulated operating companies in a jurisdiction which are then applied to the specific company's operating expense levels. Under this approach, one study can be performed for all of the companies instead of performing numerous studies. Resp. Ex. 16.0, pp. 31-32.

No other party to this proceeding had an issue with the Companies' use of the Net Lag methodology. Ms. Ebrey raises "issues" related to the CWC analysis that are not truly issues. There are no revenues considered in the Net Lag approach and, therefore, there are no non-cash items in the analysis. Her explanation that the Gross Lag methodology better addresses her issues with the treatment of revenues makes sense only if the purpose of Staff's flip-flop is intende to obtain a lower CWC requirement. There is no principled basis for Staff's change in position.

The Companies have appropriately prepared, documented and supported its cash working capital analysis. The Net Lag methodology used by the Companies has been accepted by this Commission in prior rate proceedings. No other party to this proceeding has expressed concerns with the use of the Net Lag methodology.

Employing the methodology and assumptions used in her analyses, the result will almost always be a negative cash working capital result, when the opposite should be true. Ms. Ebrey creates a scenario for each of the Companies in which the revenues considered in the analyses are less than the expense levels. In other words, under Staff's approach, the Companies

are generating operating losses on a cash basis. When the revenue lag is multiplied by the revenues (which have been reduced to exclude the return on equity, depreciation/amortization expenses, uncollectible expenses, and non-cash OPEB expenses) the result will usually be less than a higher level of expenses multiplied by the expense leads. Resp. Ex. 37.0, p. 40.

The revenue lag for the Companies is 43.24, which means that it takes 43.24 days, on average, for the Companies to receive payment from its customers and to have access to the money for service provided during a given month. Conversely, the Companies are paying providers of services, on a dollar weighted basis, approximately 40 days after services are provided. Therefore, on a net basis, the Companies are paying the vendors over three days before payment is received from the customers. Resp. Ex. 37.0, pp. 40-41.

Further, employing Ms. Ebrey's proposed gross lag methodology, the Companies are paying expenses that exceed revenue levels. According to Ms. Ebrey's analyses, the Companies are collecting between $25 million and $75 million less in available revenues to pay cash expenses. While the scenario is not logical, Ms. Ebrey's analyses shows that the Companies' shareholders would actually be providing funds to support day-to-day operations, which would mean that the Companies have a positive cash working capital requirement. Ms. Ebrey concludes, somehow, however, that the Companies have negative cash working capital requirements ranging from $1.5 million to $6.6 million. This position simply does not make sense. Resp. Ex. 37.0, p. 41.

Further, Staff's recommended cash working capital requirements are not consistent with information on receivables and payables as shown on the Companies' balance sheets. As shown in the following table, AmerenCILCO and AmerenCIPS clearly have a positive cash working capital requirement with AmerenIP at the margin. The Companies are not

advocating that the balance sheet information be used to derive the cash working capital requirements of the Companies; however the information was merely used as a sanity check to determine whether the results from the gross lag methodology proposed by Staff witness Ebrey are realistic. The sanity check confirms that Staff witness Ebrey's results are not realistic.

Company	A/R - FERC 142 ($000)	AP - FERC 232 ($000)
CILCO	49,168	37,413
CIPS	48,840	22,589
IP	106,720	108,940

Resp. Ex. 37.0, pp. 41-42.

In summary, the principal benefit of using a Net Lag methodology is that it is more intuitive in terms of its results. If the revenue lags exceed the expense leads, a positive cash working capital amount is generated. An additional benefit is that by negating the need for considering dollar revenues, it circumvents the contentious issue of identifying and removing non-cash items included in dollar revenues from the analysis. These non-cash items may include, but are not limited to, items such as depreciation, other post employment benefits, uncollectibles, return on equity, as well as other non-service related items which may be considered elsewhere such as customer deposits, revenues from special (non-service related) riders, and other miscellaneous revenues. The Net Lag methodology, consistent with the definition of a lead lag study, does consider the timing of the receipt of revenues from customers without having to specifically identify which revenues are cash or which ones are service related or considered elsewhere since, to the extent that such charges are on a bill, a customer pays both simultaneously.

2. Interest Expense LED

Staff proposes to use 366 days in the year as the basis for calculating the expense lead time on interest expense. According to Staff, this approach would be "consistent with the Companies' calculations."[2] The impact is to reduce the cash working capital requirements of AmerenCILCO, AmerenCIPS, and AmerenIP by $4,800, $8,500, and $25,000 respectively. Staff, however, is misstating the approach used by the Companies and second, is being inconsistent in her approach. Thus, her proposal for calculating the expense lead time on interest expense should be rejected. Resp. Ex. 37.0, pp. 46, 51.

Where applicable, and consistent with standard industry practice, the Companies use 365 days in their calculations of revenue lags and expense leads. Recognizing, however, that the Companies' test year was a leap year, the Companies used 366 days in the denominator when calculating a daily measure of cash working capital requirements for each expense item considered in the Companies' lead lag study (i.e., the cash working capital factor which is defined as the net lag divided by the number of days in the test year). This daily measure was then multiplied by test year expenses at proposed rates to derive the cash working capital requirements of the Companies. Thus, Ms. Ebrey is not being "consistent with the Companies' calculations." Resp. Ex. 37.0, p. 47.

Moreover, Staff's position itself seems to be internally inconsistent and thus warrants rejection by the Commission. Throughout the lead lag study, the midpoint of a period is determined by dividing 365 days by the appropriate period of time. For example, to determine the midpoint of a year, the study would divide 365 by 2 to arrive at the midpoint of the year, or 182.5 days. Resp. Ex. 37.0, pp. 47-48.

[2] Staff Exhibit 13.0, page 10, line 186.

When determining the midpoint of a year for purposes of determining the interest expense lead, Ms. Ebrey uses 366 days to arrive at a midpoint of 91.50 days. The variance in the calculations yields a difference of 0.25 days. While the use of the difference seems small, the impact on the Companies' cash working capital requirement ranges from approximately $5,000 to $25,000. Resp. Ex. 37.0, pp. 47-48.

3. Capitalization Payroll in CWC Requirements

Staff proposes to include the capitalized portion of payroll expense in the cash working capital requirements of the Companies. This is inappropriate. The capitalized portion of payroll would already be included in rate base and, if approved by the Commission, would earn a return. Second, without analyzing the payroll portion of all capital projects, it is impossible to determine whether such projects accrued an allowance for funds used during construction, which is effectively a carrying cost that is included in the overall capitalized cost. Third, Ms. Ebrey is proposing to select the capital costs associated with only one lead lag item for inclusion in the cash working capital analyses. If Ms. Ebrey is of the opinion that the cash working capital analyses should include all cash outflows, (including capital costs), then all cash outflows associated with all other elements of the cash working capital analysis should be included as well. Finally, Ms. Ebrey's recommendation effectively ensures that the Companies' cash working capital requirements will be negative by including the capitalized costs associated with payroll in the expense portion of her analyses while only reflecting revenues which, in theory, match operating expenses. In other words, Ms. Ebrey has inappropriately created an apples to oranges comparison and thus, her results should be rejected by the Commission. Resp. Ex. 37.0, pp. 45-46.

4. Payroll Withholding Taxes

This matter was resolved at hearing.

5. Expense levels to which cash working capital factors are applied.

See Section I.F.1.

ICC Staff witness Peter Lazare, IIEC witness Alan Chalfant, and Wal-Mart witness James T. Selecky each raised certain issues directly or indirectly pertaining to pension and/or OPEB benefits, those issues were addressed in significant detail in the rebuttal testimony of Ameren Companies' witness C. Kenneth Vogl, Respondents' Ex. 21.0 (see also AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0 for discussion of relevant issues). Those issues, described briefly below, are apparently resolved, as none of those witnesses disputed or questioned Mr. Vogl's testimony in their respective rebuttal testimony. The Ameren Companies reserve the right to set forth in full detail Mr. Vogl's testimony on Pension and OPEB Expenses in their reply brief.

a. ICC Staff

In his direct and rebuttal testimony, Mr. Vogl explained the key factors driving the increases in pension and OPEB expenses are interest rates, returns on equity investments, and medical inflation – factors beyond the control of the Ameren Companies. While Mr. Lazare questioned this in his direct testimony, he did not dispute Mr. Vogl's testimony on rebuttal, apparently accepting Mr. Vogl's numbers and explanations of why increases in pension and OPEB have occurred and why the pro forma levels accurately reflect the Ameren Companies' actual, recoverable expenses.

b. IIEC

IIEC witness Alan Chalfant testified: "To the extent the commission approves increased amounts of O&M expense for the adequate provision of delivery service, the amount of overhead or A&G should be increased proportionally."

Pension and OPEB expenses represent 49.6% of the increase in A&G expenses since the prior order. As detailed above, and as Mr. Vogl explained in his direct and rebuttal testimony, pension and OPEB expenses have increased dramatically since each of the Ameren Companies' last delivery services case. Pension and OPEB expenses included in the prior orders for the Ameren Companies reflected the Ameren plans at a time when they were more fully funded, as a result of the then current economic environment. In fact, the pension plans were overfunded. Due to subsequent investment performance, decreasing interest rates, and high medical inflation, the plans have become more underfunded. The pension (FAS 87) and OPEB (FAS 106) expenses included in the current case reflect the expenses of Ameren's underfunded plans, and these expenses are reasonable compared to pension and OPEB expenses for similarly sized organizations.

At the same time that plans have become underfunded, all companies offering such benefits have seen a significant increase in pension and OPEB expenses. The increases in pension and OPEB expenses are primarily the result of changes in interest rates, returns on equity investments, and medical inflation.

Thus, Mr. Vogl's testimony demonstrates that a large percentage of A&G expenses are unlikely to be correlated to any increase in O&M expense, which are not generally

subject to the same pressures and drivers. Mr. Chalfant did not dispute Mr. Vogl's testimony on rebuttal.

c. Wal-Mart

In his direct testimony, Mr. Selecky recommended "that the ICC approve a normalized level of pension and OPEB expenses to be included in Ameren Utilities' revenue requirements". (Wal-Mart Ex. 1.0., p. 33.) His approach averages the past five years of pension and OPEB expenses to determine the normalized expense amounts. As explained in Mr. Vogl's rebuttal testimony (Respondents' Ex. 21.0, pp. 8-9) and below, Mr. Selecky's recommendation is incorrect. Notably, Wal-Mart did not dispute in rebuttal the Ameren Companies' testimony regarding why Mr. Selecky's recommendation is not reasonable.

First, the only correct approach for rate recovery of pension and OPEB expenses allows for the Ameren Companies' full recovery of these expenses over time, no more and no less. As Mr. Vogl discussed in his direct testimony, and as Mr. Selecky agreed, pension and OPEB expenses can be very volatile. Mr. Selecky's proposed approach normalizes the peaks (high cost periods) while ignoring the valleys (low cost periods). Mr. Vogl testified that this approach would result in less than full pension and OPEB expenses being reimbursed by ratepayers.

Again, it is important to note that the pension and OPEB expenses approved in the prior orders were very low. These prior orders' expenses for 1999 or 2000 reflect expenses for overfunded plans that were generated by the high equity returns, higher interest rates, and lower medical costs during the late 1990s. In essence, the change in pension and OPEB expense since the prior orders simply reflects the adjustment in economic environment.

Second, pension and OPEB expenses for any given year should be equal to the benefits earned in that year plus an adjustment based on the funded status of the plan, according to FAS 87 and FAS 106, which are both in accordance with Generally Accepted Accounting Principals. (FAS 87 and 106 are explained in detail in Mr. Vogl's direct testimony, (AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0.) Since both FAS 87 and FAS 106 determine expense for the pension and OPEB plans in this manner, these expenses should be reimbursed by ratepayers on the same basis, thus ensuring that the pension and OPEB expense for any given year is tied to the current funded position of the plans. Normalizing the pension and OPEB expense so the costs are not representative of the current funded position would be inconsistent with ratemaking principles, as it would yield pension and OPEB expenses that are significantly different than the current funded position of the plans.

Ameren Companies' witness Kenneth Vogl testified that the Ameren Companies, similar to the majority of other companies, have experienced significant increases to their FAS 87 and FAS 106 expenses over the past few years. Mr. Vogl explained the key reasons for these increases, specifically, the fact that lower discount rates and higher medical costs have increased the Companies' liabilities, and that lower than expected investment returns (which result in fewer plan assets than expected), have lowered the funded status of the pension and OPEB plans.

H. Other

II. OPERATING EXPENSES AND REVENUES

A. Summary of Uncontested/Settled Issues

The Ameren Companies will provide a summary of all uncontested and settled issues in their proposed order, which will be filed with their reply brief.

B. Vegetation Management/Tree Trimming

1. ICC Staff

As described further in Section V.C, *infra*, the overwhelming evidence shows that the "no-touch" tree trimming policy advocated by Staff witness James Spencer should not be implemented. The no-touch policy is an inappropriate interpretation of NESC Rule 218. Implementation of such a rule is unnecessary, unwise, and is contrary to law, as fully set forth in Section V.C.

If the Commission were to implement Staff's proposed no-touch policy, the overwhelming evidence also shows that this would significantly increase the Ameren Companies' Distribution System Maintenance costs. Ameren Companies' witness Ray Wiesehan (Ameren Services Company Manager – Safety and Resource Management) testified that, if the Commission were to accept Staff's new interpretation of NESC Rule 218, the Ameren Companies would be forced to increase the frequency and thus the costs of vegetation management.

Currently, the Ameren Companies trim at four-year intervals. Mr. Wiesehan testified that, in order to comply with Staff's new no-touch policy, the Ameren Companies would have to convert to a two-year trimming cycle. Respondents' Exhibit 16.5 shows that the Ameren Companies' additional costs for the No Touch Policy Adjustment would increase operating expense by $27,538,000. Of this total, $17,535,000 is incremental additional ongoing costs, and the remaining $10,003,000 reflects an amortization of the additional costs that will be incurred over the next four years, in order to convert from a four-year to a two-year tree trimming cycle. The increase in operating expense of $27,538,000 is also included in the Adjustments to

Operating Income shown on Exhibits 16.1, 16.2, and 16.3. (Respondents' Ex. 16.0, pp. 5-6.) The total additional cost to achieve and maintain a "no touch" program over a four year period is $57,548,000. (Respondents' Ex. 25.0, pp. 11-12.) The Ameren Companies estimate that it will take four years to train new trimming personnel and integrate a no-touch approach into our program. (*Id.*) These costs are hardly insignificant.

Mr. Spencer has concluded, without any support, that Staff's new approach regarding NESC Rule 218 will not have a significant impact on tree trimming costs. Mr. Spencer also admits that he does not know that this is the case. (ICC Staff Ex. 10.0, p. 23, lines 577-78.) Notably, Staff has provided no analysis from any accounting or other expert to support this claim. No Staff witness took issue with any of the aforementioned dollar amounts. No Staff witness sought to undermine the above analysis.

Irrespective of the paucity of Mr. Spencer's "analysis", Mr. Wiesehan explained why Mr. Spencer's claim is not true:

> First, there is not a homogenous growth rate among the tree species that get trimmed every year. Some trees respond differently to pruning. In order to maintain a true no contact program, some trees may be required to be trimmed as frequently as every year. Second, the Ameren Companies would have to employ additional staff to manage the resources required to maintain a no touch program. Our cost estimates for maintaining a no touch program are based upon trimming our entire system at a minimum every

> two years vs. every four years, as well as continuing to do some hot spot trimming to control trees that have extremely fast growth rates. These numbers reflect only the cost for contracted services and do not include any internal loading for additional staff Ameren would have to hire to administrate a no touch program. These financial projections assume we continue to manage for removals of new trees and brush and continue to maintain our current overhanging trim practices.

(Respondents' Ex. 25.0, pp. 11-12.)

Mr. Wiesehan further testified that the no-touch policy would necessitate a two-year tree trimming cycle because the utilities would need to manage a narrowed space around the primary electric conductor. (Respondents' Ex. 25.0, pp. 9-10.) The primary conductor is the wire that distributes higher voltage electricity to the transformers located on poles of the overhead distribution system. Mr. Wiesehan notes that several industry sources support this conclusion. (*Id.*) For example, results from an Environmental Consultants Incorporated ("ECI") study entered into the record shows this type of growth is a low risk to reliability. (*Id.*) The ECI study also suggests that preventative maintenance cycle period can be based on an economically optimal period rather than strictly on the basis of maintaining line clearance. (*Id.*)

Mr. Wiesehan agreed the Ameren Companies could trim this growth more frequently; however, at current funding levels we would be forced to manage a narrower window of around the conductor, i.e more time and expense incurred. (*Id.*) Consequently, the Ameren

Companies would not pull as much growth from overhanging branches as we currently do nor remove as many volunteer or trapped trees. (*Id.*) This would lead to more trees having to be trimmed and a greater potential for overhanging limbs to break and contact the conductor, causing greater safety concerns to the general public and utility workers and poorer reliability performance. (*Id.*) This quote from the ECI study supports the Ameren Companies' position:

> "Branch diameter was shown to play a major role in conductivity, with the largest branches being much more conductive than small shoots. This work also suggests that the majorities of tree-to-conductor contacts result in high impedance faults of low current, and are relatively low risk to reliability."

(Resp. Ex. 25.0, p. 10, *quoting* Environmental Consultants Incorporated, "Species-Specific Variation in Impedance as Related to Electrical Fault Potential," June 2004.)

Further, Mr. Wiesehan testified that by not controlling new volunteer trees and brush, the Ameren Companies will have more trees to trim in the future:

> This will increase the cost and the resources required to maintain the system. Qualified trimming personnel are currently at a premium as are many skilled craftsmen. It would take several years to recruit and train new personnel. We would also have to take into consideration the impact on customer satisfaction. We would be on the customer's property more frequently, with no evidence of any enhanced benefit with regard to safety and

> improved reliability. In addition, we will be wounding trees more frequently with increased pruning and this could inhibit the trees' ability to properly compartmentalize the wound. This leads to an increase in stress on the trees, which in turn causes declining health to tree populations near the conductors, which again comes back to public safety concerns, reduced reliability and increased cost.

(Respondents' Ex. 25.0, pp. 10-11.)

Staff has presented no evidence to support Mr. Spencer's speculations to the contrary. Staff has presented no credible evidence to challenge the assertions of the ECI study, nor the expertise offered by Mr. Wiesehan.

There is no basis in fact for Mr. Spencer's claim that costs to implement the "no-touch" policy would be offset by decreases in O&M expenses. Notably, Mr. Spencer has offered nothing to support his contention, and establishes no relationship between the Ameren Companies' level of tree trimming expense and their level of outage costs. Mr. Spencer admits that he has not attempted to quantify any savings in O&M. (ICC Staff Ex. 21.0, p. 17. We doubt the Commission would ever make a revenue requirement adjustment based on a "could be " or "maybe" scenario—especially where no particular dollar value is even offered. Accordingly, there is no factual basis upon which the Commission could conclude that any increase in tree trimming expense would be offset by decreased outage costs. (Respondents' Ex. 16.0, p. 6.)

For these reasons, the Ameren Companies' should be allowed to recover their full tree trimming and vegetation expenses. For the reasons set forth in Section V.C, *infra*, the

Commission should reject Staff's new proposed "no-touch" policy. However, if the Commission should adopt such a policy, the record supports a further increase in tree trimming expenses as set forth in testimony.

2. Cities of Champaign and Urbana

In direct testimony, Cities of Champaign and Urbana ("Cities") witness Richard W. Cuthbert testified that AmerenIP had not provided adequate support for their requested tree trimming expenses. (Cities Ex. 1.0, pp.62-63.)

Since that time, the Ameren Companies have provided extensive documentation in support of their tree trimming costs, in its responses to the Cities' data requests (*see* Respondents' Ex. 16.0, pp. 5-6), and in rebuttal and surrebuttal testimony from two separate witnesses, Ron Stafford and Ray Wiesehan. Notably, the Cities did not refute the Ameren Companies' rebuttal testimony on this issue. Thus, the Ameren Companies believe that this issue is resolved, but reserve the right to present a more detailed explanation of tree trimming expense support in their reply brief.

1. ICC Staff

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C. Injuries and Damages Expense

In rebuttal testimony (Respondents' Ex. 16.0, p. 8.), the Ameren Companies agreed to normalize injuries and damages expenses per Staff's recommendation in the direct testimony of Burma Jones. As explained below, Staff's approach to normalization is reasonable and should be approved.

Both Ms. Jones and AG witness David Effron recommended normalizing injuries and damages expenses in their direct testimony. (ICC Staff Ex. 3.0, pp. 22-26; AG Ex. 1.0, pp. 17-19.) Ms. Jones recommends normalizing expenses over a four-year period, calculating the percent of claims charged against the reserve to the amounts accrued to the reserve. Ms Jones also recommends eliminating abnormal data to avoid skewing the resulting average. Mr. Effron disagrees with this approach, and recommends normalizing expenses over a five-year period.

Staff's weighted average approach is the preferred method in this case. Mr. Stafford testified that a weighted average approach to normalization is more common and generally preferred in setting various revenue and expense levels rather than the simple average normalization developed by Mr. Effron. (Respondents' Ex. 36.0, pp. 5-6.) Ms. Jones' approach recognizes that injuries and damages accruals and payments fluctuate from year to year. Notably, Mr. Effron has not opposed Staff's proposed weighted average approach to normalization of uncollectible expenses. A weighted average approach is commonly used in a ratemaking context normalize for variables such as weather, changes in depreciation rates, and cost of debt and equity.

Mr. Effron's approach, on the other hand, is effectively a cash basis approach, which is rarely, if ever, used to set revenue and expense levels for the purpose of either financial

reporting or setting rates in a ratemaking context. (Respondents' Ex. 36.0, pp. 5-6.) Using simple averages to establish revenue and expense levels that fluctuate from time to time can skew calculations, as Ms. Jones recognized in her recommended approach. (ICC Staff Ex. 3.0, pp. 23-24.)

Mr. Effron's primary criticism of Staff's approach is that he disagrees with the subjectivity involved in recording expense accruals and assessing outlying data. As Mr. Stafford testified, accruals are the accepted form of accounting for revenues and expenses. (Respondents' Ex. 36.0, p. 6.) And, Mr. Effron's recommended approach is also subjective, in that he has elected to normalize injuries and damages expense over a 5-year period vs. some other period, such as a 4-year period or instead based on either test year or post test year payments.

The Commission should adopt Staff's recommended weighted average approach to injuries and damages expense normalization and reject the AG's proposal.

D. Rate Case Expense

The Ameren Companies are entitled to recover their reasonably incurred rate case expenses. Staff, however, has inexplicably chosen to disallow a large portion of the Ameren Companies' reasonably incurred rate case expenses, without logical explanation.

These adjustments fall into three categories:

(1) an undefined class of delivery service rate case expense costs that Ms. Jones claims has not been supported by documentation,

(2) the cost of an electric depreciation study that the Ameren Companies used to determine appropriate depreciation rates, and

(3) the cost of the Ameren Companies' rate case to establish a means for procuring power after December 31, 2006.

The Commission should reject Staff's unfounded recommendations and allow the Companies to recover their reasonably incurred rate case expenses.

1. Delivery Services

a. Staff's Proposed Disallowance of Rate Case Expenses Must be Rejected.

The Ameren Companies have requested recovery of approximately $2.7 million in rate case expenses for this case, as the total amount of expenses for all utilities combined. (Respondents' Ex. 16.9; ICC Staff Ex. 14.0, p. 1; Respondents' Ex. 36.5, page 1.) To put this number in perspective, the Commission recently approved Commonwealth Edison's recovery of approximately $7.3 million in rate case expenses for their delivery services rate case expenses. (Final Order, ICC Docket 05-0597, p. 47; *see also* Respondents' Ex. 36.0, p. 12.) That level of expense is consistent with rate case expenses approved for Commonwealth Edison in other cases. (Final Order, ICC Docket 05-0597, p. 47.) While Commonwealth Edison is able to spread its rate case expenses over a larger customer base, fewer customers does not mean less work for the Ameren Companies in litigating their rate cases.

This level of expense demonstrates that the Ameren Companies have diligently managed the rate case expenses for three utilities at a level far below what the Commission, and Staff, has deemed reasonable for one.

Nonetheless, Staff has recommended allowing only approximately $1.4 million in rate case expenses for all of the Ameren Companies, thus disallowing almost half of the requested amount. This disallowance represents all of the Ameren Companies' rate case expense costs incurred after the Ameren Companies filed their rebuttal testimony. (Tr. at p. 583-84.)

Staff's justification for this disallowance is not clear.

What is clear from the record is that Staff has not based its recommended disallowance on any quantitative or qualitative analysis of the Ameren Companies' expenses or rate case estimates. (Tr. at p. 608, lines 2-22, p. 609, lines 1-14.) Staff does not dispute that rate cases take time, and that the time of an expert or an attorney costs money. (*Id.*; Tr. at pp. 583-85.) Staff has been provided with the hourly rates of the Ameren Companies' expert witnesses and counsel in the form of contracts and "numerous" invoices, as well as total cost estimates for those services. (*Id.*; ICC Staff Ex. 14.0, p. 5.) Staff has acknowledged that the Ameren Companies have incurred costs since their rebuttal filing. (Tr. at 581, lines 21-22, Tr. at 582, lines 1-2.) Staff agrees that their costs are ongoing. (Tr. at 587, lines 12-16.) But Staff has chosen to disregard that information. Staff has not analyzed or reached any determination of whether the Ameren Companies are being overcharged at the rates indicated in contracts and invoices, or whether the total requested amounts for those services are unreasonable. (Tr. at p. 608, lines 2-22, p. 609, lines 1-14.)

Staff's only apparent basis for the recommended disallowance is that the Ameren Companies' rate case estimates at time of filing were lower than their estimates at the rebuttal stage. (ICC Staff Ex. 14.0, p. 4.) Working backward, Ms. Jones speculates that this overly optimistic cost estimate must have been the result of "verbal communications with [the Companies'] outside service providers." (ICC Staff Ex. 14.0, p. 4.) Ms. Jones ultimately concludes that "verbal communications" are inherently unreliable. (Tr. at p. 606.) Thus, any costs that have not been invoiced are unreasonable.

Ms Jones has admitted that the Ameren Companies are allowed to recover their reasonable rate case expenses, regardless of whether they have already been invoiced. (Respondents' Exhibit 36.0, p. 10.) Yet, the gist of Ms. Jones' testimony and recommendation is that if a cost has not been invoiced and paid, it is not reasonable and may not be recovered. (*See* Tr. at p. 589.) Ms. Jones has not identified any particular rate case expense that she believes is unsupported, and has not found any particular cost to be unreasonable.

Ms. Jones' testimony is that, even if the Ameren Companies have a longstanding relationship with outside counsel or other service providers, that service provider's cost estimate cannot be reasonable if it is spoken. And, if the Ameren Companies based their original cost estimates in this case on spoken word, those cost estimates are "unreasonable." Any actual costs incurred in this case that have not yet been billed are thus "unreasonable," too.

On lengthy cross-examination, Ms. Jones would not admit to *any* other relevant factor – just written estimates – in determining the reasonableness of a utility's rate case costs. (*See* Tr. at 580 – 606.) Not evidence of hourly rates, not contracts, not a lengthy relationship with a service provider, not market comparables, not case comparables, not common sense. (*Id.*) If a service provider's pre-filing estimate is not in writing, there is simply "nothing else," upon which to base a reasonableness determination of the cost of the service. (Tr. at p. 605, lines 18-19.)

The Ameren Companies strongly disagree with Ms. Jones' opinion. Mr. Stafford testified that the Ameren Companies used the most accurate information available at the time of filing – including service provider rates, contracts, letters of engagement and historical data, and

yes, spoken communication – to derive their original cost estimates. (Respondents' Ex. 36.0, pp. 11-12.) The Ameren Companies have cultivated long relationships with many of the service providers they use in a rate case, and thus are able to use historical data and experience to shape cost estimates. The Ameren Companies have a clear interest in being sure that their estimates are as accurate as possible. But, there is no crystal ball that can forecast what costs will actually be. Rate case costs are inherently difficult to estimate, because it is impossible to predict what will happen in a litigated case. The Ameren Companies cannot simply choose not to fully participate in litigation because doing so would cost more than we originally thought or hoped. Rate case estimates thus naturally change over time as actual costs are realized and as circumstances warrant. Obviously, rate case cost estimates that are currently available are more accurate than those that were available at time of filing, because they are now based on actual data.

Ms. Jones acknowledges that there are variables outside of a utility's control that can affect rate case costs. (Tr. at pp. 591-594.) She also acknowledges that expenses incurred over a utility's original rate case estimate are not necessarily unreasonable. (Tr. at pp. 590, 591.) Ms. Jones even acknowledges that the Ameren Companies have provided contracts and "numerous invoices" to Staff supporting rate case costs. (ICC Staff Ex. 14.0, p. 4.) Nonetheless, Ms. Jones concludes, without explanation, that those invoices "do not necessarily support that the amounts the Companies want to recover from ratepayers is reasonable." (*Id.*)

There is nothing in Ms. Jones testimony to support Staff's proposed disallowance. The record is clear that the Ameren Companies have managed to keep their rate case expenses to an extraordinarily low level, a level far below what the Commission has deemed reasonable in other cases. The Ameren Companies have provided Staff with ample support for all of their rate

case costs, including the most accurate estimates available, contracts, letters of engagement, and "numerous invoices." Staff's proposed disallowance is without merit and should be disregarded in its entirety.

The Commission should be mindful of the alternative left to the Ameren Companies should Staff prevail. It would appear the prudent course would be for the Ameren Companies to solicit written, highly conservative estimates of projected rate case expenses, to assure that invoices "track" estimates. (Tr. at 590, 4-11.) The Ameren Companies do not believe that this approach would be consistent with keeping outsourcing costs low. Staff's approach would give the Ameren Companies no choice but to ensure that their vendors and contractors assisting in the cases err on the side of caution when providing estimates.

b. CSS Consulting and Manpower, Inc. Invoices Detail Reasonably Incurred Rate Case Expenses.

The only specific costs that Ms. Jones proposes disallowing are certain invoiced amounts for CSS Consulting and Manpower, Inc. Ms. Jones claims that those documents do not indicate that the invoiced services provided for are related to this rate case. Mr. Stafford has testified, under oath, that the costs detailed in those invoices are in fact related to this rate case:

> The costs included in the Ameren Companies' rate case expense related to these companies should be recognized as a legitimate cost in the preparation and processing of information for these rate cases. Specifically, $7,000 of the CSS Consulting work was directly related to collection of historical asset data from the Companies' property records to assist in preparation of the depreciation study. The remaining $5,000 was for work performed in preparation of the minimum filing requirement schedule C-13 requiring four years of historical affiliate transaction data. The use of CSS Consulting provided the opportunity for the Ameren Companies to tap the expertise of a former Manager retired from the Controllers group within Ameren Services, who had a great

> deal of familiarity with Ameren's property accounting records and affiliate transaction detail. For Manpower, $1,000 was incurred for costs of one individual to assist with preparation of data for the depreciation study. The remaining $5,000 has been an ongoing process in response to the volume of data requested by Staff witness Ebrey in her audit of Plant Additions. Specifically, the individual in question has, under my direction and supervision, pulled and/or copied thousands of sheets of paper to help the Ameren Companies compile data requested by Ms. Ebrey, along with assisting in the review of her proposed Plant Additions and Pro Forma Plant Additions adjustments, and assembly of various Rebuttal and Surrebuttal Exhibits and supporting documentation in support of the Ameren Companies' response to these issues.

(Respondents' Ex. 36.0, pp. 13-14.) Mr. Stafford's testimony sufficiently supports that those invoices detail reasonably incurred rate case expenses. Staff's recommendation to disallow such costs must be rejected.

2. Post-2006 Basic Generation Services

There are two unresolved issues related to the Ameren Companies' Post-2006 Basic Generation Services rate case ("Post-2006 Rate Case").

First, similar to its position regarding delivery services rate case expenses, Staff has recommended only those costs which have been invoiced to date. (*See* ICC Staff Ex. 14.0, Schedule 14.02, p. 1.) As in this case, the Ameren Companies' expenses in the Post-2006 Rate Case are necessary, unavoidable and ongoing. Staff has not disputed this fact. For the same reasons discussed above, Staff's recommended disallowance of Post-2006 Rate Case expenses not invoiced to date is unsound and should be rejected. The Ameren Companies should be allowed to recover the full amount of their Post-2006 Rate Case expenses, whether through the Supply Procurement Adjustment ("SPA") or through delivery services rates.

Second, Staff has recommended disallowing recovery of rate case expenses related to the Post-2006 Rate Case through delivery services rates. Staff instead recommends recovering those expenses through the SPA. (ICC Staff Ex. 14.0, p. 10-12). Staff's recommendation ignores the fact that the BGS Proceeding benefited all of the Ameren Companies' customers. (Respondents' Ex. 36.0, pp. 19-20.) Staff's recommendation is thus not consistent with cost-causation principles.

Staff does not dispute that Section 16-103(c) of the Public Utilities Act requires the Ameren Companies to be the electricity supply "provider of last resort," and thus must offer supply service options to all its delivery services customers. Nor does Staff dispute that the Ameren Companies' ability to provide these options was secured through the Post-2006 Rate Case. Staff merely counters that "[t]he fact that the Companies must offer service to whoever wants it predates the [Post-2006 Rate Case]." (ICC Staff Ex. 14.0, p. 11.) This statement offers nothing to address *how* the Ameren Companies would be able to meet this statutory obligation to be the electricity supply provider of last resort after 2006.

The Ameren Companies' *ability* to provide supply service to whoever wants it after December 31, 2006, does not predate the Post-2006 Rate Case. That ability was secured through the Post-2006 Rate Case. All Ameren Companies' customers thus benefited from the Post-2006 Rate Case. Cost causation principles thus dictate that Post-2006 Rate Case costs should be allocated to all of the Ameren Companies' customers.

If the Ameren Companies were to recover their BGS proceeding costs through the SPA, only a portion of the Ameren Companies' customers would actually pay for costs that were

incurred for the benefit of all customers. And, due to the nature of the Ameren Companies' customer populations, such costs would be disproportionately borne by residential customers, who do not currently have the same supply service options as large industrial customers. (Respondents' Ex. 36.0, p. 20.) Under Staff's proposal, large industrial customers with supply service options could choose alternative electricity suppliers in the short term, while reserving the right to return to the Ameren Companies' supply service options in the future without paying for those options. In short, Staff's proposal violates cost causation and allocation principles and should be rejected.

3. Depreciation Study

In preparation for this rate case, the Ameren Companies commissioned a depreciation study to determine the Ameren Companies' current appropriate depreciation rates. (Respondents' Ex. 36.0, p. 14.) The depreciation study was an important and necessary expenditure to determine appropriate depreciation rates for all of the Ameren Companies, especially because the Companies' rates have been frozen for almost ten years. (*Id.*)

Staff witness Jones has recommended disallowing recovery of expenses the Ameren Companies incurred in conducting its depreciation study (Staff Ex. 3.0, p. 24). Ms. Jones has testified that expenditures related to the depreciation study are not a recoverable rate case expense, because the Ameren Companies have not proposed any changes in depreciation rates. (Staff Ex. 14.0, p. 10.)

The record shows that the depreciation study supported a small decrease in depreciation rates for AmerenCIPS and AmerenCILCO, but a very large increase in depreciation rates for AmerenIP. (Respondents' Ex. 36.0, p. 15.) Ms. Jones claims that the Ameren

Companies' use of the depreciation study was not reasonable, because the Ameren Companies did not request a change in depreciation rates even though the study supported such a change. For that reason, Ms. Jones argues that the costs for the study should be disallowed. (ICC Staff Ex. 14.0, p. 10.)

Mr. Stafford testified that the Ameren Companies analyzed the results of the study, and the decision not to request a change in depreciation rates was based on these results. (Resp. Ex. 36.0, pp. 15-16.) Although the results of the depreciation study supported a moderate overall increase in expense, there was a large disparity between the increase in rates recommended for AmerenIP versus the other utilities. (*Id.*) This increase would have caused AmerenIP's rates to jump substantially higher. (*Id.*)

Because the Ameren Companies are very concerned about the affect of an increase in rates on our customers, the decision was made that an increase in depreciation rates would not be requested until a more complete history of ownership for all of the utilities had been established. (*Id.*) When a depreciation study is conducted, analysts conduct field work and interview company employees about specific asset use and performance. (*Id.*) This information is of great use in determining accurate depreciation rates. (*Id.*) The results of such interviews and field work may differ after Ameren Corporation has developed a fuller history of ownership of its assets, thus affecting the results of the depreciation study itself. (*Id.*)

Weighing these factors, in light of the significant disparity in depreciation study results between utilities and the impact that a requested change in depreciation rates could have on AmerenIP customers, the Ameren Companies decided not to request an increase in rates.

(*Id.*) The Ameren Companies determined that the results of the depreciation study under prevailing circumstances supported maintaining the status quo. (*Id.*) Further, based on the depreciation study, the Ameren Companies are requesting permission to reallocate the AmerenIP depreciation reserve in order to mitigate future impacts of changes in depreciation rates. (*Id.*; *see also* discussion *infra* at I.B.4.)

Ms. Jones' argument implies that the only reasonable use of a depreciation study is to request rates in exact accordance with the study's results. There is simply no basis in law or in practice for this conclusion.

Notably, Staff did not propose a change in depreciation rates, either, even though Staff received the initial results of the study on April 13, 2006, well in advance of its rebuttal testimony filing. (Tr. at p. 579, line 22, p. 580, lines 1-3.)

The Ameren Companies have presented ample evidence that the results of the depreciation study, in light of prevailing circumstances, supported their ultimate decision not to request a change in rates. Staff's proposed disallowance is groundless and must be rejected.

E. A&G Expenses

1. Functionalization

Staff witness Lazare and IIEC witness Chalfant, challenge the level of A&G expenses for the Ameren Companies. ICC Staff Ex. 17.0, pp. 10-28; IIEC Ex. 5.0, pp. 10-16. As will be discussed, both Mr. Lazare's and Mr. Chalfant's recommendations are severely flawed, for several reasons. In sum, however, both approaches rely on a generalized view of A&G, rather than a review of specific A&G expenses. Mr. Lazare attempts to recreate his own

version of a virtually integrated power company as if Ameren had never divested its generation business from AmerenCILCO and AmerenCIPS. He bases his recommended total A&G expenses on the results of this analysis and then applies his AmerenCILCO results to AmerenIP, since Ameren did not acquire and does not own the generation assets previously owned by IP. Mr. Chalfant's approach is even more extreme, in that he does not even acknowledge specific, detailed evidence presented by the Ameren Companies in testimony or in responses to data requests.

While both Mr. Lazare and Mr. Chalfant have had the opportunity to review hundreds of Company responses to data requests that deal with A&G expenses, neither witness has placed any reliance on this information to recommend that any specific A&G expenses should be allowed for recovery, or not be allowed for recovery, with the exception of Mr. Lazare's acknowledgement of submitted evidence regarding pensions and benefits expenses. Neither witness has identified any specific A&G expenses that have been imprudently incurred. While they allege that a portion of A&G costs support non-regulated production functions, they provide no factual basis for that allegation. Neither witness has identified any specific A&G expenses that do in fact support or relate to non-regulated production functions. They merely assume this to be the case and challenge the Companies to prove them wrong.

Mr. Stafford explained that, to the extent test year A&G expenses support non-regulated production functions, the Ameren Companies have assigned an allocable portion of test year A&G expenses to non-regulated production functions on the books of AmerenCILCO and AmerenIP. In the test year, AmerenCIPS did not own any production assets, nor did they have any employees assigned to production. Therefore, no A&G expenses were assigned to non-

regulated production for AmerenCIPS. Resp Ex. 36.0, pp.21-22. He also explained that none of the the test year A&G expenses support non-regulated production functions of other Ameren affiliates involved in the generation of electricity, because A&G expenses supporting non-regulated production functions of other Ameren affiliates are recorded on the books of the other Ameren affiliates. No portion of the costs recorded on the books of the other Ameren affiliates also included in the requested level of A&G for AmerenCILCO and AmerenCIPS. Id. at 23-24.

Mr. Stafford also explained that Ameren determines whether A&G expenses should be recorded on the books of the Ameren Companies vs. other Ameren affiliates based on the work being performed. If an employee of AmerenCIPS, for example, charges his/her time to an A&G account, and he/she performs work for another affiliate, then the affiliate will be issued a bill for that work, and reimbursement to AmerenCIPS will be recorded as a reduction to A&G expense. If that same employee routinely performs work for other Ameren affiliates, that employee would instead be employed by Ameren Services Company. In that case, time reporting would be governed by the General Services Agreement ("GSA"). In the example used above, the employee performing work on behalf of the other affiliate would have the ability to directly assign such time to the affiliate. The A&G expense associated with the specific work performed would in turn be recorded on the books of that affiliate. If instead the work performed were to benefit more than one Ameren affiliate, the GSA provides a number of different allocation methods that could be used to allocate costs common to more than one legal entity, within the Ameren affiliate group of companies. Resp. Ex. 36.0 at 24.

Both Mr. Lazare and Mr. Chalfant suggest that there should be a relationship between A&G and other O&M expenses. There is no basis for such a relationship. To provide

context for this issue, Mr. Stafford reviewed the Ameren Companies' O&M and A&G expenses compared with a proxy group of ten other utilities with similar megawatt hours and customers. He found the Ameren Companies compare very favorably with the other utilities for A&G expenses in relationship to other O&M expenses. More specifically, in the Ameren Companies' surrebuttal filing, A&G expenses divided by distribution plus customer expenses, is 76.01%. This compares with the ten-utility proxy group average of 104.51%. As such, even if the argument could be made that there is a direct relationship between A&G other O&M, then the overall level of A&G costs requested by the Ameren Companies is reasonable. Resp. Ex. 36.0 at 25-26.

With regard to his proposal not to use the AmerenIP results, Mr. Lazare argued that "there must be some evidence to indicate that the company should receive an even greater increase than it proposed in direct". Mr. Lazare, however, did not identified any valid reason for not making the adjustment, other than he does not like the results. There are numerous reasons why this logic is faulty. First, Mr. Lazare has not identified any statutory or legal restriction on the ability of Staff witnesses to propose a greater increase for a particular cost, or group of costs, that a company proposes. Second, Staff witnesses have accepted a number of adjustments and corrections to what the Ameren Companies originally proposed in these proceedings. Some of these adjustments, such as corrections to the AMS Reallocation, and updated Rate Case expense, have resulted in increases. In addition, Mr. Lazare himself is inconsistent in approach, in that he has proposed an increase to AmerenCILCO general and intangible plant compared to the Ameren Companies' proposal. In the case of general and intangible plant, Mr. Lazare was consistent in that he proposed a uniform approach, whether positive or negative, for each of the

Ameren Companies, but for some reason, he has elected to not follow a uniform approach for A&G expenses. Resp. Ex. 36.0, p. 29.

In sum, the Ameren Companies have supported their requested level of A&G costs, have demonstrated that such costs are reasonable both in total in comparison with other O&M expenses, and have provided detailed support for not only pensions and benefits costs, but also for other A&G costs. In addition, the Ameren Companies have supported the fact that other Ameren affiliates involved in non-regulated production functions have substantial A&G costs independent of the costs recorded on the books of the Ameren Companies. The burden of proof has been met by the Ameren Companies in these proceedings to demonstrate that the requested level of A&G costs are reasonable. Further, neither Mr. Lazare nor Mr. Chalfant has identified a single cost that is imprudent. Neither Mr. Lazare nor Mr. Chalfant has identified a single A&G cost that is not properly allocated to the Ameren Companies. These witnesses have offered only unfounded and general assumptions, which are at odds with the specific facts. In summary, while Mr. Lazare's corrected approach would produce an even higher level of A&G expense than the level requested by the Ameren Companies, the Ameren Companies' recommendation is that the flawed approaches submitted by Mr. Lazare and Mr. Chalfant should be entirely disregarded, and the Commission in turn should authorize A&G expense included in the Ameren Companies' surrebuttal revenue requirement.

2. Incentive Compensation

The Ameren Companies have requested full recovery of their incentive compensation costs through rates. The record shows that incentive compensation costs are a necessary component of the Ameren Companies' compensation package, and thus should be

recoverable in rates. Further, Staff witness Jones' testimony accedes that ratepayers are at least partial beneficiaries of the Ameren Companies' incentive compensation payouts (ICC Staff Ex. 14.0, p. 13, lines 250-51), thus supporting at least a partial recovery of incentive compensation costs.

Ameren Companies' witness Krista Bauer testified that incentive compensation payouts are a standard business practice that is necessary for any business to attract and maintain a well-qualified, efficient, and focused workforce. (Respondents' Ex. 44.0, pp. 1-2.) Incentive compensation does not merely give the Ameren Companies a competitive edge in attracting employees – incentive compensation is an essential component of a fair and market-based compensation package. (*Id.*)

The ratepayers' and the Ameren Companies' interests are aligned on this point. Ratepayers need the Ameren Companies to be able to compete with other companies for the best and most qualified employees. Reliable and efficient electricity service depends on it. The alternative to offering a competitive compensation package consisting of both base and incentive pay is to simply eliminate incentive pay, which would likely increase fixed labor costs and reduce employee interest/focus on key operational goals. This arrangement would not benefit anyone, most importantly the ratepayers.

Ratepayers also benefit from incentive compensation payouts through realization of operational goals, motivated by the incentive payout formulas. (*Id.*) Incentive payouts are driven by performance on key customer-focused operational metrics. (*Id.*) The quality utility

service that our customers are receiving is dependent on high performance from employees who are focused on the Ameren Companies' operational goals.

The Ameren Companies use many customer-focused incentive compensation goals/measures to focus their employees' efforts on activities that will benefit customers. (*Id.* at p. 3.) The Ameren Companies are consistently concerned with ensuring reliable service to customers. As a result, measures of electricity reliability are regularly placed on scorecards and used to determine incentive compensation payouts. (*Id.*) For example, the Ameren Companies' employees have shared goals to reduce the frequency of electric service disruptions in each of the divisions they serve. (*Id.*) Responding to one of Mr. Effron's points, this is but one example of enhanced efficiencies achieved through incentive compensation payouts.

In addition, the Ameren Companies' employees have goals to decrease the duration of any interruptions that may occur by quickly restoring service to the customer. (*Id.*) To facilitate these goals, employee teams are formed to identify and implement process improvements. (*Id.*) Undeniably, a strong focus on increasing service reliability benefits every customer in the Ameren Companies' territory.

Another key metric on which the Ameren Companies base incentive awards is customer satisfaction. (*Id.*) Customer satisfaction is regularly measured and analyzed to determine how to improve service even more. (*Id.*) This focus on customer satisfaction has resulted in many activities designed to enhance the customer experience, with respect to both the contact center and field services. (*Id.*) Our focus and measurement of customer service has resulted in both AmerenCIPS and AmerenCILCO recently receiving certification by JD Powers

for Call Center Operations. Undeniably, a strong, incentive-based focus on increasing both the technical and professional service that customers receive when interacting with the Ameren Companies directly benefits their customers. (*Id.*)

Another salient metric used to measure incentive-based payouts is safety, as measured by lost workday away cases. (*Id.*) Reducing lost workdays serves to reduce operating costs, another concern raised by Mr. Effron.

When Ameren Company employees do not work in a safe manner, they risk serious injury to themselves and/or others. (*Id.* at 4.) One of the results of injury is that employees spend time off work and are unable to provide service to the customer. Ameren and its subsidiaries have continued to place a greater and greater emphasis on safety and are heavily reinforcing this measure by giving it significant weight in incentive calculations. (*Id.*) The Ameren Companies have seen many initiatives designed to increase safe work practices and as a result, a fairly significant decrease in lost workday away cases. (*Id.*) Again, this is a practice that undeniably benefits the customer. Ultimately, Ameren's key performance indicators, reinforced by incentive payouts, have resulted in significant attention to important customer issues. This focus has resulted in both tangible benefits (such as JD Power Certification and reduced lost workday away cases, etc.) and intangible benefits (employee alignment with key goals, prioritization of goals, etc) (*Id.*) – all of which help the Ameren Companies provide safe, and reliable service to our customers.

The Ameren Companies recognize that employee motivation is necessary to align individual goals with the Ameren Companies' operational goals. Incentive compensation

programs motivate employee behavior by focusing employees on important business and operational goals and rewarding them when they achieve or make progress towards the goals.

Staff witness Jones comments that customers would continue to provide this funding even if the target earnings levels were not met, and the plans are discretionary, as additional reasoning for the disallowance. (ICC Staff Ex. 14.0, p. 13.) But this criticism is not in line with the Ameren Companies' actual practices. The Ameren Companies have a long history of paying out incentive compensation awards and recognize this form of compensation as a necessary part of an employees' overall wage and benefit package. (Respondents' Ex. 44.0, p. 5.)

Ameren's incentive plans may provide payouts in any given year that are greater or less than those provided during the test year. (*Id.*) But over time, those year-to-year deviations are expected to balance out. (*Id.*) Over the past five years Ameren's incentive plans have been funded above target, on average. (*Id.*) Additionally, business lines have achieved the stretch goals they have set as part of incentive planning at levels which, on average, permit between 80% and 90% of the business line component of the incentive awards to be paid. (*Id.*) Thus, Ameren has a consistent history of paying incentive awards to employees.

Incentive compensation is a critical tool for attracting, motivating and retaining the Ameren Companies' employees. (*Id.* at 6.) Historically, the Ameren Companies' plans have been funded and have provided employees with rewards for both group and individual performance. (*Id.*) Our intention is to continue this practice.

Ms. Jones' claim that shareholders are the primary beneficiaries of incentive compensation packages (ICC Staff Ex. 14.0, p. 13, lines 250-51) is not true, as ratepayers clearly benefit directly from this plan. Incentive compensation packages provide benefits all around – primarily to employees, but also to ratepayers, as described above. However, even if the statement were true, it implicitly acknowledges these shared ratepayer benefits. Thus, Ms. Jones' testimony implicitly supports only a partial disallowance of incentive compensation costs.

The record supports the Ameren Companies full recovery of incentive compensation benefits. But, at the very least, the Commission should allow partial recovery of these costs (for example, 50%), based on Staff's testimony alone.

3. Pension and OPEB Expense

ICC Staff witness Peter Lazare, IIEC witness Alan Chalfant, and Wal-Mart witness James T. Selecky each raised certain issues directly or indirectly pertaining to pension and/or OPEB benefits, those issues were addressed in significant detail in the rebuttal testimony of Ameren Companies' witness C. Kenneth Vogl, Respondents' Ex. 21.0 (see also AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0 for discussion of relevant issues). Those issues, described briefly below, are apparently resolved, as none of those witnesses disputed or questioned Mr. Vogl's testimony in their respective rebuttal testimony. The Ameren Companies reserve the right to set forth in full detail Mr. Vogl's testimony on Pension and OPEB Expenses in their reply brief.

a. ICC Staff

In his direct and rebuttal testimony, Mr. Vogl explained the key factors driving the increases in pension and OPEB expenses are interest rates, returns on equity investments, and

medical inflation – factors beyond the control of the Ameren Companies. While Mr. Lazare questioned this in his direct testimony, he did not dispute Mr. Vogl's testimony on rebuttal, apparently accepting Mr. Vogl's numbers and explanations of why increases in pension and OPEB have occurred and why the pro forma levels accurately reflect the Ameren Companies' actual, recoverable expenses.

b. IIEC

IIEC witness Alan Chalfant testified: "To the extent the commission approves increased amounts of O&M expense for the adequate provision of delivery service, the amount of overhead or A&G should be increased proportionally."

Pension and OPEB expenses represent 49.6% of the increase in A&G expenses since the prior order. As detailed above, and as Mr. Vogl explained in his direct and rebuttal testimony, pension and OPEB expenses have increased dramatically since each of the Ameren Companies' last delivery services case. Pension and OPEB expenses included in the prior orders for the Ameren Companies reflected the Ameren plans at a time when they were more fully funded, as a result of the then current economic environment. In fact, the pension plans were overfunded. Due to subsequent investment performance, decreasing interest rates, and high medical inflation, the plans have become more underfunded. The pension (FAS 87) and OPEB (FAS 106) expenses included in the current case reflect the expenses of Ameren's underfunded plans, and these expenses are reasonable compared to pension and OPEB expenses for similarly sized organizations.

At the same time that plans have become underfunded, all companies offering such benefits have seen a significant increase in pension and OPEB expenses. The increases in

pension and OPEB expenses are primarily the result of changes in interest rates, returns on equity investments, and medical inflation.

Thus, Mr. Vogl's testimony demonstrates that a large percentage of A&G expenses are unlikely to be correlated to any increase in O&M expense, which are not generally subject to the same pressures and drivers. Mr. Chalfant did not dispute Mr. Vogl's testimony on rebuttal.

c. Wal-Mart

In his direct testimony, Mr. Selecky recommended "that the ICC approve a normalized level of pension and OPEB expenses to be included in Ameren Utilities' revenue requirements". (Wal-Mart Ex. 1.0., p. 33.) His approach averages the past five years of pension and OPEB expenses to determine the normalized expense amounts. As explained in Mr. Vogl's rebuttal testimony (Respondents' Ex. 21.0, pp. 8-9) and below, Mr. Selecky's recommendation is incorrect. Notably, Wal-Mart did not dispute in rebuttal the Ameren Companies' testimony regarding why Mr. Selecky's recommendation is not reasonable.

First, the only correct approach for rate recovery of pension and OPEB expenses allows for the Ameren Companies' full recovery of these expenses over time, no more and no less. As Mr. Vogl discussed in his direct testimony, and as Mr. Selecky agreed, pension and OPEB expenses can be very volatile. Mr. Selecky's proposed approach normalizes the peaks (high cost periods) while ignoring the valleys (low cost periods). Mr. Vogl testified that this approach would result in less than full pension and OPEB expenses being reimbursed by ratepayers.

Again, it is important to note that the pension and OPEB expenses approved in the prior orders were very low. These prior orders' expenses for 1999 or 2000 reflect expenses for overfunded plans that were generated by the high equity returns, higher interest rates, and lower medical costs during the late 1990s. In essence, the change in pension and OPEB expense since the prior orders simply reflects the adjustment in economic environment.

Second, pension and OPEB expenses for any given year should be equal to the benefits earned in that year plus an adjustment based on the funded status of the plan, according to FAS 87 and FAS 106, which are both in accordance with Generally Accepted Accounting Principals. (FAS 87 and 106 are explained in detail in Mr. Vogl's direct testimony, (AmerenCILCO, AmerenCIPS, and AmerenIP Ex. 11.0.) Since both FAS 87 and FAS 106 determine expense for the pension and OPEB plans in this manner, these expenses should be reimbursed by ratepayers on the same basis, thus ensuring that the pension and OPEB expense for any given year is tied to the current funded position of the plans. Normalizing the pension and OPEB expense so the costs are not representative of the current funded position would be inconsistent with ratemaking principles, as it would yield pension and OPEB expenses that are significantly different than the current funded position of the plans.

Ameren Companies' witness Kenneth Vogl testified that the Ameren Companies, similar to the majority of other companies, have experienced significant increases to their FAS 87 and FAS 106 expenses over the past few years. Mr. Vogl explained the key reasons for these increases, specifically, the fact that lower discount rates and higher medical costs have increased the Companies' liabilities, and that lower than expected investment returns (which result in fewer plan assets than expected), have lowered the funded status of the pension and OPEB plans.

4. Major Medical

In Staff witness Peter Lazare's rebuttal testimony, he accepts that the rebuttal testimony of Ameren Companies' witness Marla Langenhorst supports at least 3.9% of the proposed $12.4 million in Administrative and General ("A&G") expenses for Major Medical. (ICC Staff Ex. 17.0, lines 266-273.) However, as noted by Ms. Langenhorst in surrebuttal (Respondents' Ex. 43.0), Mr. Lazare's small concession grossly misstates Ms. Langenhorst's testimony.

Ms. Langenhorst testified in rebuttal that Ameren Services Company ("Ameren Services") has successfully limited growth in Major Medical expenses to a 3.9% increase, which is much lower than the national average increase of 6.1%. (Respondents' Ex. 22.0, p. 5.) These statistics were offered to demonstrate the reasonableness of the Ameren Companies' costs, by showing the proven results of Ameren Services' efforts to keep Major Medical expenses in check. (Respondents' Ex. 43.0, p. 2.) This data was not offered as an "explanation" or "accounting" for Major Medical expenses, as Mr. Lazare claims. The Ameren Companies have provided an accounting of their actual, proven costs through the testimony and schedules of Ronald Stafford. Staff has conducted its own audit of the Ameren Services' accounting methodology, and has identified no Major Medical expenses as unreasonably incurred. The publicly available and undisputed fact that medical expenditures have increased at a national average rate of 6.1% (as shown in Respondents' Ex. 22.2) also provides a common sense explanation for the Ameren Companies' requested increase. Mr. Lazare's failure to grasp this point is difficult to swallow.

Ms. Langenhorst further clarified that the 3.9% statistic is based on an overall average increase for all Ameren subsidiaries, excluding AmerenIP, and including only part of AmerenCILCO for the latter part of this time period. (Respondents' Ex. 43.0, p. 2-3.) This clarification shows that the statistic is inappropriate for accounting purposes, but does not dilute Ms. Langenhorst's original point that the Ameren Companies' current system is commendable for its ability to limit health care cost growth to rates that are well below the national average.

Ms. Langenhorst testified that Ameren Services' will continue its efforts to develop new and innovative programs designed to curb health care costs. (Respondents' Ex. 43.0, p. 3.) However, many such programs are already in place. (*Id.*) Thus, future reductions in the rate of health care cost growth may not be achievable, from a practical perspective. There are also many other factors determining growth that are beyond the Ameren Companies' control. (Respondents' Ex. 23.0, pp. 4-5.) Realistically, those factors should be expected to increase the Ameren Companies' health care costs in the future at rates that are consistent with the national average.

Ameren Services cannot provide immunity to medical inflation. Their efforts have only slowed the rate at which the Ameren Companies' costs will increase. There is no way to completely insulate the Ameren Companies from those increases, aside from extreme measures such as medical plan termination. Such dramatic measures only serve to affect the ability to attract and retain the employees needed to run our operations. Providing decent health care for our employees is critical for the Ameren Companies' success, and it is consistent with what competing companies provide to their employees. Mr. Lazare's opinion that Major

Medical expenses are increasing at a higher rate than he would like them to provides no plausible contest against undisputed evidence of the Ameren Companies' actual, reasonable expenses.

5. Other A&G

See subsection II.E. 1.

F. Effect of Ameren Ownership on Illinois Power Expenses

G. Other

III. RATE OF RETURN

B. Summary of Uncontested/Settled Issues

The Ameren Companies will include a summary in the Draft Order accompanying their Reply Brief.

C. Capital Structure

1. Capital Structure Measurement Period

The Ameren Companies recommend measuring all components of the capital structure at 12/31/05, making the measurement period consistent with regard to all components. Resp. Ex. 15.1, p. 2.

Staff witness Pregozen recommended advancing the capital structure measurement dates for AmerenCILCO and AmerenCIPS in lieu of pro forma adjustments. The Companies agree with Mr. Pregozen's recommendation to advance the capital structure measurement dates rather than make pro forma adjustments in this instance. Resp. Ex. 15.1, p. 1. However, they disagree with Mr. Pregozen's use of a June 30, 2005 measurement date for all of the long-term components of AmerenCILCO's and AmerenCIPS' capital structures while using a last twelve months ("LTM") December 31, 2005 measurement period for short-term debt. Mr. Pregozen states in his direct testimony on lines 264-265 that 'advancing the measurement date

ensures that all components of the capital structure are measured on a consistent basis. His approach does not achieve that consistency. Mr. Pregozen measures short-term debt over a period which lasts six months beyond the date at which he measures common equity, long-term debt and preferred stock. By doing this he has mismatched the measurement date of permanent capital balances with the ending date for the period for measuring short-term debt balances. Id. at 1-2.

The Ameren Companies' proposal eliminates the mismatch between the measurement date of the long-term components (common equity, long-term debt and preferred) with the measurement period of short-term debt. Furthermore, a consistent measurement period eliminates the need for the type of conjecture Mr. Pregozen undertook when he chose a twelve month period as 'a better estimator of the amount of short-term debt CILCO has maintained to finance its operation…' This is the sort of subjective speculation that the Commission no doubt sought to eliminate when it drafted its latest capital structure measurement period instructions as part of the filing requirements. Also, the buildup of short-term debt that Mr. Pregozen refers to is the type of pattern that can precede a replacement by a permanent capital source. Id. at 2-3.

The Companies also recommend measuring all components of AmerenIP's capital structure as of December 31, 2005. Again, for purposes of consistency the Companies would recommend measuring the balance of net short-term debt to LTM ended December 31, 2005. Moving forward the measurement dates for AmerenIP would be consistent with the measurement periods for AmerenCILCO and AmerenCIPS while incorporating the latest data available. Further, Statement of Financial Accounting Standards 141 allows for a period of one year following the closing date of the acquisition to identify, measure and assign amounts to purchase accounting adjustments. Since Ameren's acquisition of AmerenIP was completed on September

30, 2004, a capital structure date of December 31, 2005 would allow the Companies to incorporate final purchase accounting adjustments, while avoiding the need for either pro forma adjustments or estimated adjustments. Resp. Ex. 15.1, p. 3.

2. Imputed Capital Structure

The Ameren Companies and the Staff proposed using the Companies' actual capital structure, although they differed with respect to the proper measurement period. (See Section III.B.1.) CUB witness Bodmer and IIEC witness Gorman proposed the use of hypothetical capital structures.

CUB witness Bodmer recommends developing hypothetical capital structures for AmerenCIPS, AmerenCILCO and AmerenIP that would be consistent with BBB ratings based on his analysis. Mr. Nickloy explained why this would not be reasonable. First, his analysis uses an approach based on S&P's financial ratio guidelines. Second, Mr. Bodmer is effectively arguing that AmerenCIPS' and AmerenCILCO's then "A" category ratings were too high and that a "BBB" is the "correct" or most reasonable rating category or level for a utility. As will be discussed, Mr. Bodmer almost got his wish – but at the present capital structure. See Ameren Freetly Cross Ex. 1. There is no room for further ratings degradation.

The equity ratio for each of AmerenCIPS, AmerenCILCO and AmerenIP has been taken into account by the rating agencies as part of their assignment of the ratings for these companies. For example, AmerenIP's equity ratio is a result of Ameren's recapitalization efforts at this utility. Notwithstanding this equity ratio, AmerenIP's ratings are only marginally within the investment grade category. If AmerenIP were to reduce its equity ratio, e.g. replace equity capital with debt capital, AmerenIP's key cash flow ratios would deteriorate and thus place negative pressure on AmerenIP's already marginal ratings. Resp. Ex. 14.0, p. 6.

Utilities are capital intensive businesses. Utilities have a fundamental responsibility to provide reliable utility services such as the provision of electricity or natural gas to their customers. Utilities must access capital to fund working capital requirements, to make continuing investment in their utility infrastructure, and replace existing capital as it matures. Resp. Ex. 14.0, p. 6. It naturally follows then that utilities must have reliable access to capital at reasonable cost. The credit quality of a utility is directly related to its ability to reliably access the credit and capital markets for the debt capital it requires and the cost of that capital. Id.

If the Commission were to accept Mr. Bodmer's premise that AmerenCIPS and AmerenCILCO are too highly rated, and accordingly, make adjustments to their allowed cost of capital based on this, the Commission would effectively be punishing these two utilities for their history of prudently financing and capitalizing their business and assets, and would be calling into question the utility managements' strategy of and commitment to maintaining strong investment grade utilities. An electric and gas transmission and distribution utility with an "A" category rating is not unusual nor is it unreasonable. In S&P's Regulated Transmission and Distribution – Electric, Gas and Water U.S. utility segment, there are 33 electric, gas or combination utilities with corporate credit ratings of A- or higher alone. This number does not include utilities with BBB+ corporate credit ratings and A- ratings for their senior secured/first mortgage debt. Resp. Ex. 14.0, p. 7.

At BBB, a utility is only two ratings notches away from having sub-investment grade, or junk, ratings - a ratings situation which plagued Illinois Power Company prior to its acquisition by Ameren and a ratings situation which plagued the prior parent companies of both AmerenCILCO and AmerenIP. Two notches is not a lot of "ratings cushion" to absorb factors or conditions which could apply negative pressure to the ratings. As we have seen, these factors

can include a political environment which places risk around the expected ability of the utility to recover its costs of providing utility service. These factors could also include other situations such as periods of heavy capital investment, especially if such investment has a long lead time and the utility must debt fund capital expenditures (construction work in process) without receiving incremental cash flows during the construction period and/or until a future rate case to offset the additional debt. Adding debt without adding incremental cash flow has negative and harmful effects on the financial metrics discussed above. These are challenges that AmerenIP is facing today. Resp. Ex. 14.0, pp. 7-8.

Another result of having lower ratings would be an increase in borrowing costs. Investors/lenders will demand higher interest rates for providing debt capital to a lower rated credit. Resp. Ex. 14.0, p. 8.

Mr. Bodmer contends the ICC should encourage distribution companies to take advantage of high debt capacity given their very low business risk. There is much that is problematic about that recommendation. It is by no means clear that Ameren's three Illinois distribution utilities have "high debt capacity." Their senior secured debt ratings are now uncomfortably close to sub-investment grade, as discussed in Section III.E. Adding debt without adding incremental cash flow would only negatively pressure these ratings further. This situation is indicative of these utilities having an *absence* of high debt capacity. Resp. Ex. 14.0, pp. 8-9.

Moreover, Ameren's credit agreements have leverage covenants which limit the amount of debt that can be incurred by Ameren's Illinois utilities. Violation of this covenant would result in an event of default and would prevent these borrowers from utilizing the facility – a very important resource for external short-term liquidity. Resp. Ex. 14.0, p. 9.

Also, these utilities do not have "very low" business risk. S&P assigns a business profile score of "4" to each of AmerenCIPS and AmerenIP. This is a numerical score on a scale of "1" (excellent) to "10" (vulnerable) representing S&P's assessment of utilities' qualitative business or operating characteristics and risk including such factors as markets and service area economy, competitive position, fuel and power supply, operations, regulation and management. A business profile score of "1" represents an entity of lower risk than one with a business profile score of "10". Of the 33 transmission and distribution utilities referenced above, all have business profile score of "1", "2" or "3". None is rated as "4". Apparently, S&P does not believe that AmerenCIPS and AmerenIP have "very low" business risk. AmerenCILCO's S&P business profile score is "6." Resp. Ex. 14.0, p. 9.

Mr. Bodmer is essentially saying that Ameren's Illinois utilities should have much more debt in their capital structures and Ameren should just "lever up" these utilities. Not only would this be inconsistent with Ameren's commitment to maintaining the credit quality of these utilities, this would in fact be a credit hostile action. The rating agencies' reaction to this would go well beyond a simple reassessment of the resulting impact on the utilities' financial measures. This would also have a major negative impact on qualitative factors which are just as important in the ratings process. Management's credibility and commitment to credit quality would be seriously questioned. Resp. Ex. 14.0 p. 10.

The fallout from this would be significant. Ratings almost certainly would decline, borrowing costs would increase, reliable access to capital would be diminished, the ability to reliably and cost-effectively fund utility infrastructure would be harmed, the risk of financial default would increase, and investor confidence would be impaired. These

consequences would be incompatible with the utilities' commitment to reliably provide utility service over the long-term. Resp. Ex. 14.0, p. 10.

Mr. Bodmer's recommendation to lever up Ameren's Illinois utilities and maintain debt ratios of at least 60% would be especially inappropriate for AmerenIP. Following Mr. Bodmer's recommendation would effectively "undo" and render moot all of those efforts and represent possibly an unprecedented (especially if the time parameter is considered) unwinding of a recapitalization strategy, raising and deployment of equity capital, and shift in wealth between classes of investors. Ameren infused $865 million of equity (which Ameren raised specifically for that purpose) in the form of cash into AmerenIP which was used to reduce debt. Premiums of about $100 million paid to bondholders were necessary to reduce that debt. These actions were consistent with achieving the conditions imposed on the Commission's approval of Ameren's acquisition of Illinois Power Company in Docket No. 04-0428. It is not appropriate that Ameren and AmerenIP should be punished for complying with the Commission's Order in that Docket in this regard, especially given Ameren's actions led to the achievement of the positive results that Ameren contemplated: the restoration of investment grade ratings, improved access to capital (including regaining access to short-term working capital) and a resulting equity ratio in the range of 50-60%. Resp. Ex. 14.0, p. 11.

AmerenIP's equity ratio is a result of Ameren's recapitalization efforts for this utility. Notwithstanding this equity ratio, AmerenIP's ratings are only marginally above the minimum investment grade rating level (the rating agencies would have course considered AmerenIP's equity ratio as part of their overall assessment and assignment of ratings). Reducing this equity ratio would imply a trade of debt capital for equity capital resulting in a net increase of debt. An increase in debt would also translate into an increase in total interest obligations.

All leading to negative pressure on ratings given the decline in key financial metrics. Unless it can be demonstrated that AmerenIP's ratings are unreasonably high, it would be inappropriate to argue that its equity ratio is too high. Resp. Ex. 14.0, p. 12.

Mr. Gorman recommends that the Commission impute a capital structure at AmerenIP. In support of his postion, he argues that because S&P views the credit risk of, and rates AmerenIP based on the consolidated credit risk of Ameren and its subsidiaries, the capital structure of AmerenIP should be reasonably consistent with the capital structures of Ameren's other utilities.

First, S&P is unique in its consolidated ratings approach. Neither Moody's nor Fitch utilizes this approach, instead relying on a more conventional stand-alone, legal entity-based approach. Moody's and Fitch recognize that Ameren's utilities are separate legal entities, are capitalized independently of one another (and in fact, are affiliated only because of Ameren's merger and acquisition efforts), do not share or jointly participate in the issuance and investment of permanent capital, and importantly, are not obligated for the obligations of one another. The fact that they are affiliated does not directly influence their capital structures. In fact, AmerenIP has only been affiliated with Ameren's other utilities since September 30, 2004. Resp. Ex. 14.0, pp. 12-13.

Second, "consolidated" does not mean "the same or similar." It means "added together." Ameren could have utilities engaged in interstate natural gas transportation, water, telephone, etc. and still be subject to S&P's consolidated rating approach. Resp. Ex. 14.0, p. 13.

Third, although Ameren's Illinois utilities are exposed to a number of similar business risks, they are and remain separate legal entities with separate operations, separate cash flow profiles and separate debt and preferred stock obligations. Their respective capital

structures reflect these factors and related ratings effects. AmerenIP's permanent capital cannot finance the operations of its affiliates and vice versa. The Cities witness Richard W. Cuthbert acknowledges this in his direct testimony where he states, "Each Ameren subsidiary has separate operations and financial structures, with separate debt, preferred equity, and common equity of each company's capitalization." Also, AmerenIP's capital structure is in part a result of certain adjustments made by S&P including imputed indebtedness and interest obligations associated with AmerenIP's purchased power obligations. Resp. Ex. 14.0, p. 13.

Fourth, Mr. Gorman's recommendation is at odds with a fundamental cost of service ratemaking principal of ignoring the costs and effects of affiliates as part of setting rates for a given utility. Resp. Ex. 14.0, p. 13.

3. CILCO $4.64 Preferred Stock Expense

Mr. Pregozen stated that because he could not locate documentation related to AmerenCILCO's $4.64 Series issuance expenses, he could not recommend inclusion in the Company's Embedded Cost of Preferred Stock calculation. This exclusion is not justified. Mr. Pregozen argued that 'sometimes Staff inadvertently overlooks an adjustment due to circumstances beyond its control' as his basis for not including the expense in this case. Not only is this argument dubious, it seems implausible for past Staff witnesses to incorrectly *include* an expense item as a result of overlooking an adjustment. Instead, an overlook would result in an *exclusion* of an adjustment. Further, both Company and Staff witnesses included this expense item in the Company's most recent DST case (Docket Nos. 01-0465/01-0530/01-0637 (Cons.)) and gas case (Docket No. 02-0837) without disagreement and the item was embedded in the Commission's final order. Staff's arguments, therefore, not only suffer from lack of substance

and faulty logic but also go against past Staff testimony and Commission precedent. Resp. Ex. 35.0, pp. 8-9.

D. Measurement Date of Short-term and Variable Interest Rates

Moving forward the measurement period of the calculation of short-term debt negated the need for the pro forma adjustment relating to the September 2004 $75 million equity infusion at AmerenCILCO. However, given that the calculation of short-term debt at AmerenCILCO involves an average of the net short-term debt balances over the twelve months ended December 31, 2005, a pro forma adjustment for the May 2005 equity infusion of $100 million remains a necessity. Mr. Pregozen erred by not making this adjustment for the months of January, February, March and April of 2005. The AmerenCILCO cost of short-term debt schedule, shown in Respondents' Exhibit 15.4, correctly accounts for this adjustment. By accounting for this equity infusion, the correct balance of net short-term debt at AmerenCILCO is reflected during those four months and results in a proper LTM average short-term balance. Resp. Ex. 15.1, p. 6.

Mr. Pregozen argued in his rebuttal testimony that he 'generally opposes moving the dates for measuring the components of the cost of capital forward in time during the rebuttal phase of rate proceedings'. Recent Staff practice has shown otherwise, evidenced by Staff witness Michael McNally's update of interest rates in his rebuttal testimony in the AmerenCIPS and AmerenUE gas cases (Docket Nos. 02-0798/03-0008/03-0009 (cons.)). Resp. Ex. 35.0, p. 2. Mr. McNally used updated (May 21, 2003) spot rates for AmerenUE variable auction rate pollution control bonds for his *rebuttal* testimony dated June 5, 2003. The long-term capital structure components in this case were measured as of June 30, 2002. The Commission's order adopted Mr. McNally's position by including these updated (as of May 21, 2003) rates in their

final order. Id. Mr. McNally also cited Docket No. 99-0534 (a Mid American Energy Company gas rate proceeding) in his testimony which addressed this issue. The following is an excerpt from the order in this Mid American case:

> Staff asserts that the Commission has consistently used the most recent market spot rate or a forecasted rate to determine the cost of short-term debt and variable rate long-term debt. Staff cites the following cases: Order, Docket No. 86-0310, Medina Utilities Corporation, April 15, 1987, p. 9; Order, Docket No. 86-0342, Lake Holiday Utilities Corporation, April 15, 1987, pp.11-12; Order, Docket No. 86-0480, Galena Territory Utilities, Inc., September 2, 1987, p. 12; Order, Docket No. 92-0116, Illinois-American Water Company, February 9, 1993, p. 62; Order, Docket No. 93-0252, Central Telephone Company of Illinois, May 4, 1994, p. 33; Order, Docket No. 94- 0065, Commonwealth Edison Company, January 9, 1995, p. 95; Order, Docket No. 95-0219, Northern Illinois Gas Company, April 3, 1996, p. 39.

The Commission's conclusion in its order stated 'Based on the above arguments, it is clear that the cost of short-term and variable rate long-term debt should be measured using current interest rates… These current rates are, in the Commission's opinion, the best estimates of future rates.'

Although Mr. Pregozen did not agree with updating the short-term interest rates and variable rate pollution control bond interest rates to mid-May 2006, he moved the measurement dates for the variable interest rates to April 4, 2006 to coincide with both the measurement date for the short-term interest rates that he used in his direct testimony as well as the date that Staff witness Ms. Freetly measured the equity market rate of return to revise her cost of equity in her rebuttal testimony. However, Mr. Pregozen offers no precedent or filing instructions to suggest that all cost components of capital structure need to be measured as of the same date. The arguments and citations that I have noted above for updating short-term and variable interest rates are silent on other cost components including the cost of equity. Mr.

McNally, in the AmerenCIPS and AmerenUE case cited above, did not update his cost of equity recommendation when he updated variable and short-term interest rates. Resp. Ex. 35.0, p. 3.

Another issue with Mr. Pregozen's variable rate and short-term interest rate measurement date of April 4, 2006, was that it was conveniently placed just before significant increases in the rates of the variable rate pollution control debt. On April 17th, 18th and 21st AmerenIP's auction series 1997 A, B, and C increased 60.5, 35 and 50 basis points, respectively. On April 17th, AmerenIP's auction series 2001A (non-AMT) increased 35 basis points while AmerenIP's 2001AMT auction series 2001 AMT increased 30 basis points. On April 19th, CIPS auction series 2004 increased 25 basis points while the CILCO auction series 2004 increased 34 basis points. These significant increases in the cost of the variable rate pollution control bonds which happened nearly three months ago cannot be ignored. The interest rate environment today is very much different today than it was on April 4th. Since this date three month Libor, a key short-term interest rate, has increased about 48 basis points. Also since April 4th, the Federal Reserve has increased the Fed funds target rate twice for a total of 50 basis points amid elevated inflation worries. Further, Fed funds futures market as of Friday, July 7th was pricing better than a two-thirds chance (67%) for another Federal Reserve Fed funds rate increase at their August 8th meeting. So not only have rates risen significantly higher over the past three months, there is a good chance that rates are going to increase further. Resp. Ex. 35.0, pp. 3-4.

Mr. Gorman recommends that a recent 6-month average should be used for the variable rate pollution control bonds and short-term debt rather than the interest rate for these securities on any one specific date. Mr. Gorman's recommendation has been rejected by the Commission on several occasions. The arguments and case precedence cited earlier in favor of current spot rates obviously run counter to Mr. Gorman's proposal. In fact, the Commision's

order in the AmerenCIPS and AmerenUE gas cases (Docket Nos. 02-0798/03-0008/03-0009 (cons.) left no doubt on how it views situations such as this when it made its ruling amid a historically low interest rate environment:

> The Commission agrees with Staff that there has not been a showing that historical interest rates are more representative of future interest rates than is the most recent spot rate. Moreover, even it was true that interest rates tend to follow some sort of cyclical pattern there is no evidence that they are mean reverting. As Staff suggests, in recent years the Commission has routinely rejected the use of historical average interest rates in favor of current interest rates when establishing the cost rate for variable rate long-term debt. The Commission is of the opinion that mere existence of relatively low interest rates is not a sufficient basis to use an average of historical interest rates to establish the cost for variable rate long-term debt.
>
> …Consistent with its decisions in recent rate cases where this issue has been addressed, the Commission finds that current interest rates are superior to historical averages for establishing the cost of variable rate long-term debt.

Resp. Ex. 35.0, pp. 4-5.

Mr. Pregozen argued against AmerenCILCO's $100 million pro-forma adjustment to the short-term debt balances of January through April 2005 to account for a May 2005 equity infusion, claiming that it pretends that the Company refinanced $100 million of short-term debt with common equity before January 1, 2005, although the refinancing did not occur until May 2005.

The pro-forma adjustment was made to four months of data, January 2005 through April 2005, recognizing that without the adjustment the last twelve month average short-term debt balance would be misleading and overstated. The equity infusion that occurred in May 2005 was used to permanently finance the short-term debt balance at AmerenCILCO. The adjustment was made to account for a known and measurable transaction and was both necessary

and prudent to arrive at a proper last twelve-month level of short-term debt at AmerenCILCO. Resp. Ex. 35.0, p. 5.

First, Mr. Pregozen's claim that he did not have sufficient time to verify the accuracy of the adjustments and thus AmerenIP's capital structure components should not be measured as of December 2005 is far from convincing enough to disregard this data. The Staff had more than a month to prepare rebuttal testimony. Additionally, the Company has made employees available to Staff to answer questions and explain Company filings and in fact conducted a call with Mr. Pregozen on March 10th to explain the AmerenIP purchase accounting adjustments. Further, the purchase accounting adjustments that I have detailed in earlier testimony in this case were not finalized at December 31, 2004, just three months after the acquisition was finalized. Accounting rules dictate that these adjustments can identified, calculated and adjusted up to twelve months after closing of the acquisition. Resp. Ex. 35.0, p. 6. Lastly, Mr. Cuthbert agrees with the Ameren Companies' position. As he stated in his rebuttal testimony, he 'generally believe[s] it is best to use the actual capital structure for a recent representative period.'

Mr. Pregozen suggests that the December 31, 2004 measurement date is optimal for AmerenIP but not optimal for either AmerenCIPS or AmerenCILCO and believes that the capital structure measurement date for AmerenCIPS and AmerenCILCO should have absolutely no bearing on the measurement date for AmerenIP. He claims that AmerenIP's capital structure need not be measured at the same point in time as AmerenCIPS and AmerenCILCO any more than at the same point in time as Commonwealth Edison. While AmerenIP, AmerenCIPS and AmerenCILCO are separate legal entities and have their own capital structures, there are good reasons to have consistent dates. First, unlike Commonwealth Edison, AmerenIP along with

AmerenCIPS and AmerenCILCO are under a single consolidated docket having filed cases on the same date and share the same test year. Under these circumstances, there needs to be a compelling reason why the three utilities *would not* have consistent measurement dates. The Companies agreed with Mr. Pregozen's recommendation to move forward the capital structure measurement dates for AmerenCIPS and AmerenCILCO in lieu of pro-forma adjustments. Similarly, AmerenIP's capital structure measurement date should be moved forward to account fully for the updated acquisition related purchase accounting items. And in all three of the companies' cases, the more recent data makes for a more relevant and representative capital structure -- vitally important in that will be used as a basis for future rates. Resp. Ex. 35.0, pp. 6-7.

E. Cost of Illinois Power TFTNs

Mr. Pregozen suggests that the AmerenIP Transitional Funding Trust Notes ("TFTN") coupon rate should not be calculated using a monthly compounded methodology. Mr. Pregozen argues that by compounding monthly, the Ameren Companies overstate the cost of AmerenIP's TFTNs. He supports his claim by comparing the TFTNs to "most bonds" while ignoring the fact that they are far different from most bonds. Mr. Pregozen's argument to annualize the monthly discount rate by multiplying the rate by twelve assumes that the IFC collections are remitted by AmerenIP to the indenture trustee on a monthly basis, which is not true in this case. In fact, AmerenIP remits funds to the trustee on a daily basis, and those funds are unavailable to the company once remitted. The trustee makes interest and principal payments to bondholders quarterly, but this is irrelevant to AmerenIP's cost of debt. Resp. Ex. 15.1.

F. Cost of Equity

The Ameren Companies proposed a return on equity of 11%. The Ameren Companies presented the testimony of Kathleen McShane, a cost of capital expert employed by Foster Associates, Inc. Ms. McShane performed a discounted cash flow ("DCF") test, an equity risk premium, or CAPM, test and a comparable earnings test. The midpoint of her recommendations exceeded 11%, but the Ameren Companies decided to take the low end of her range, in order to mitigate the effect of the rate increase on all customer classes. Resp. Ex. 1.0, p. 3.

Ms. McShane's analysis and recommendations, took into account the following considerations (Resp. Ex. 3.0, pp. 3-6):

> (1) The allowed return on equity should reflect the risk profile and cost of capital that would apply to delivery services. A sample of relatively "pure play" natural gas distributors (LDCs) serves as a proxy for the stand-alone delivery services of AmerenCILCO; the LDC sample's cost of equity represents a reasonable estimate of the cost of equity for AmerenCILCO's delivery service.
>
> The estimates of the cost of equity do not, however, incorporate the extraordinary level of political and regulatory risk that the Illinois utilities currently face. Her recommendation assumes that the Illinois utilities will be allowed to set rates that will allow the timely recovery of all prudently incurred costs, including a fair return on investment.
>
> (2) In arriving at a recommended return, no single test result should be given exclusive weight. Each of the various tests employed provide a different perspective on a fair return. Each test has its own strengths and weaknesses, which vary with both the business cycle and stock market conditions.
>
> (3) Both the DCF and the equity risk premium ("ERP") tests are market-related tests for measuring the cost of attracting capital by reference to market values. By contrast, the comparable earnings test, which reflects returns on book equity, directly addresses the fairness standard enunciated in the courts, e.g.,
>
>> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. [*Bluefield Water Works &*

Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923)].

(4) For the purposes of determining a fair return on equity for a utility, the critical factor that needs to be recognized is that the cost of capital is determined in the capital markets. The cost of capital reflects the market value of the firm's capital, both debt and equity. While the DCF test estimates the return required on the market value of common equity, regulatory convention applies that return to the book value of the assets included in rate base. When the market value of a company's stock is close to the book value, the DCF test result can be directly applied to book value. The further the market value of equity is above book value, the greater the extent to which an unadjusted current DCF cost of equity understates the fair return on book equity. Without an adjustment to the DCF cost rates that recognizes the significant deviation between current market value and book value, the application of the DCF test will, by definition, significantly understate the return on original cost book value that investors require. Estimates of the cost of attracting capital derived from the equity risk premium tests also tend to understate a fair return on book equity for reasons similar to those applicable to the DCF model.

(5) At a minimum, a financing flexibility allowance sufficient to maintain a market/book ratio in the range of 1.05-1.10 is required. At that level, new equity could be issued without impairment of the existing shareholders' investment. This allowance, however, does not recognize the higher financial risk inherent in the book value capital structures to which the market-derived cost of equity is applied relative to the market value capital structures on which the cost of attracting equity is based. To recognize the higher financial risk inherent in the lower book value common equity ratios to which the allowed return is applied, a further adjustment is required . A third economic rationale for adjusting the cost of attracting equity capital is the recognition that the competitive model, which regulation attempts to emulate, supports an equilibrium market/book ratio of assets equal to the market/replacement cost. The upper end of the ranges for both the DCF and equity risk premium test results represents the return on book equity compatible with a longer-term equilibrium market/book ratio of approximately 1.5 times, a level that is approximately equivalent to a market-to-replacement cost ratio of 1.0.

(6) In principle, the comparable earnings test is most compatible with regulation on an original cost book value rate base. However, given the Commission's prior reliance on market-derived tests, she used the comparable earnings test results to demonstrate the reasonableness of the application of the market-derived tests as adjusted for a long-run equilibrium market/book ratio.

The estimation of a fair return on equity starts with a recognition of the objective of regulation. That objective is to simulate competition, i.e., to establish a regulatory framework that will mimic the competitive model. Under the competitive model, the required return on

equity is expected to reflect the opportunity cost of capital, i.e., a return that is commensurate with the returns available on foregone investments of similar risk. Resp. Ex. 3.0, pp. 6-7.

The objective of regulation, in conjunction with a utility's obligation to serve, has given rise to multiple criteria for a fair and reasonable return. A fair return is one that provides a utility with the opportunity to:

1. earn a return on investment commensurate with that of comparable risk enterprises;

2. maintain its financial integrity; and,

3. attract capital on reasonable terms.

The ability to attract capital is not synonymous with being allowed a return comparable with those of similar risk entities. A return that simply allows a utility to attract capital, irrespective of the cost, does not lead to the conclusion that it is compatible with the comparable returns standard. Resp. Ex. 3.0, p. 7.

These criteria give rise to two separate standards, the capital attraction standard and the comparable returns, or comparable earnings, standard. The fact that the allowed return is applied to an original cost rate base is key to distinguishing between the capital attraction and comparable earnings standards. The base to which the return is applied determines the dollar earnings stream to the utility, which, in turn, generates the return to the shareholder (dividends plus capital appreciation). When the allowed return on original cost book value is set, a market-derived cost of attracting capital must be converted to a fair and reasonable return on book equity. The conversion of a market-derived cost of capital to a fair return on book value ensures that the stream of dollar earnings on book value equates to the investors' dollar return requirements on market value. Resp. Ex. 3.0, pp. 7-8.

Some historical context, in conjunction with an explanation of the related economic concepts, may assist in understanding the basis for the need to convert a market-derived cost of capital to a fair return on the original cost book value of equity. In the early years of rate of return regulation in North America, there was considerable debate over how to measure the investment base. The controversy arose from the objective that the price for a public utility service should allow a fair return on the fair value of the capital invested in the business. The debate focused on what constituted fair value: Was it historic cost, reproduction cost, or market value? Ultimately, the courts opted for the "reasonableness of the end result" rather than the specification of a particular method of rate base determination.[3] The use of a historic cost rate base became the norm because it provided an objective, measurable point of departure to which the return would be applied. There is no prescription, however, that the historic cost rate base itself constitutes the "fair value" of the investment. Resp. Ex. 3.0, p. 8.

Nevertheless, regulators' application of a capital market-derived "cost of attracting capital" to a historic rate base in principle will result in the market value of the investment trending toward the historic cost based on the erroneous assumption that this equates to "fair value". The "fair value equals original cost" result arises from the way "cost" has typically been interpreted and applied in determining other cost elements in the regulation of North American utilities. For most utilities, rates are set on the basis of book costs; that concept has been applied to the cost of debt and depreciation expense, as well as to all operating and maintenance expenses. Resp. Ex. 3.0, p. 9.

For economists, the theoretically appropriate definition of cost is marginal or incremental cost. Historic costs have been substituted for marginal or incremental costs for two

[3] *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 591 (1944)).

reasons: first, as a practical matter, long-run incremental costs are difficult to measure; second, for the capital intensive utility industries, pricing on the basis of short-run marginal costs would not cover total costs incurred. Resp. Ex. 3.0, p. 10.

The determination of the return on common equity for regulated companies has traditionally been a "hybrid" concept. The cost of equity is a forward-looking measure of the equity investors' required return. It is, therefore, an incremental cost concept. The required equity return is not, however, applied to a similarly determined rate base (that is, current cost). It is applied to an original cost rate base. When there is a significant difference between the historic original cost rate base and the corresponding current cost of the investment, application of a current cost of attracting capital to an original cost rate base produces an earnings stream that is significantly lower than that which is implied by the application of that same cost rate to market value. The divergence between the earnings stream implied by the application of the return to book value rather than market value is magnified as a result of the long lives of utility assets. Resp. Ex. 3.0, p. 10.

The current cost of attracting capital is measured by reference to market values. The DCF test, for example, measures the return that investors require on the market value of the equity. For a utility regulated on the basis of original cost book value, the current cost of attracting equity capital is only equivalent to the return investors require on book value when the market value of the common stock is <u>equal</u> to its book value. As the market value of the equity of regulated utilities increases above its book value, the application of a market-value derived cost of equity to the book value of that equity increasingly understates investors' return requirements (in dollar terms). Resp. Ex. 3.0, pp. 10-11.

Some would argue that the market value of utility shares should be equal to book value. However, economic principles do not support that conclusion. A basic economic principle establishes the expected relationship between market value and replacement cost which provides support for market prices in excess of original cost book value. That economic principle holds that, in the longer-run, in the aggregate for an industry, market value should equal replacement cost of the assets. The principle is based on the notion that, if the market value of firms exceeds the replacement cost of the productive capacity, there is an incentive to establish new firms. The existence of additional firms would lower prices of goods and services, lower profits and thus reduce market values of all the firms in the industry. In the opposite circumstance, there is an incentive to disinvest, i.e., to not replace depreciated assets. The disappearance of firms would push up prices of goods and services and raise the profits of the remaining firms, thereby raising the market values of the remaining firms. In equilibrium, market value should equal replacement cost. In the presence of inflation, even at moderate levels, absent significant technological advances, replacement cost should exceed the original cost book value of assets. Consequently, the fair market value of utility shares should be expected to exceed their book value. If no adjustment is made to the market-derived cost of equity to account for that principle, the allowed level of earnings will tend to lead to asset values that fall short of fair value and that will discourage utilities from making critical infrastructure investments. Resp. Ex. 3.0, pp. 11.

Ms. McShane applied the discounted cash flow model, equity risk premium tests (including the capital asset pricing model), and the comparable earnings test. In arriving at my recommendation, she gave primary weight to the market-based tests, that is, the discounted cash flow and equity risk premium tests. The comparable earnings test was used as a test of the

reasonableness of the DCF and ERP results. Reliance on multiple tests recognizes that no one test produces a definitive estimate of the fair return.[4] Each test is a forward-looking estimate of investors' equity return requirements. However, the premises of each of the three tests differ; each test has its own strengths and weaknesses. In principle, the concept of a fair and reasonable return does not reduce to a simple mathematical construct. It would be unreasonable to view it as such. Resp. Ex. 3.0, p. 12.

In contrast to the cost of debt, the cost of equity is not a directly observable number. No one can know with certainty what is in each investor's mind. The cost of equity must be inferred from the available data using models that attempt to simply capture the way investors collectively price common equity. Since investors commit capital for many different reasons, there is no way to be certain what factors account for their decisions. The discounted cash flow and equity risk premium tests represent two conceptually different ways that investors often approach estimating the return they require on the market value of an equity investment. Both are intuitively appealing, and both are relatively simple in principle to apply. Ultimately, however, both are simplified, stylized models of complex behavior that result in different estimates of the return that investors require to provide equity capital. Resp. Ex. 3.0, p. 12.

The discounted cash flow approach proceeds from the proposition that the price of a common stock is the present value of the future expected cash flows to the investor, discounted at a rate that reflects the riskiness of those cash flows. If the price of the security is known (can be observed), and if the expected stream of cash flows can be estimated, it is possible to

[4] As stated in Bonbright, "No single or group test or technique is conclusive." (James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates*, 2nd Ed., Arlington, Va.: Public Utilities Reports, Inc., March 1988).

approximate the investor's required return (or capitalization rate) as the rate that equates the price of the stock to the discounted value of future cash flows. Resp. Ex. 3.0, p. 13.

There are multiple versions of the discounted cash flow model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock. In determining the DCF cost of equity for a benchmark utility, Ms. McShane utilized both a constant growth and a two-stage model. Resp. Ex. 3.0, p. 13.

In applying the DCF test, the objective is to set the return component of the delivery service tariffs. Thus, in principle, the return should reflect the stand-alone principle, that is, the cost of capital for delivery service, which is a "wires" function. Most of the publicly-traded electric utilities operate not only the "wires" business, but also have generation assets. These utilities would not be appropriate proxies for AmerenCILCO's delivery service. It is not possible to select an adequate sample of "wires-only" electric utilities, i.e., companies which are predominantly transmission and distribution utilities. Therefore, she applied the discounted cash flow test to a sample of 12 local gas distribution utilities (LDCs) that serve as a proxy for the delivery operations of the Ameren Companies. Resp. Ex. 3.0, p. 14.

Delivery service, which is part of the "wires" operations of an electric utility, is functionally similar to natural gas distribution. The key difference between electric delivery service and gas distribution is that most gas distributors continue to both sell and deliver natural gas. Delivery service, however, represents solely the "transportation" of power that customers have purchased either from a Retail Energy Supplier or from the incumbent utility through the

Power Purchase Option. Nevertheless, gas distributors are permitted to pass through to customers the differences between actual and forecast gas costs, subject to prudency. Thus, the risk that they will not fully recover commodity costs is very limited. As a result, the business risks associated with the "wires" operations of an electric utility are more analogous to those of gas distribution than to the business risks faced by the majority of publicly-traded electric utilities, whose consolidated operations include generation, both regulated and unregulated. Resp. Ex. 3.0, pp. 14-15.

There is a critical caveat to that conclusion. The application of the LDCs' equity return requirement to AmerenCILCO is premised on a "typical" level of regulatory risk. "Typical" in this context means that the regulatory environment is sufficiently stable and predictable to assure the investor that the utility has a reasonable opportunity to recover all prudently incurred costs on a timely basis, including a fair return on investment. There is significant concern presently that Illinois does not offer such an environment, as evidenced by recent comments and debt rating actions by S&P, Moody's and Fitch for the Ameren utilities, as well as for other Illinois utilities (e.g., Commonwealth Edison). These comments and actions have been driven expressly by recent political intervention in the regulatory process, which creates uncertainty for investors. Ms. McShane's return recommendations explicitly excludes consideration of any regulatory uncertainty that may exist in Illinois as a result of the recent politicization of the regulatory environment. Were recent actions and statements by some Illinois state officials and their impact on regulatory risk to be factored into the analysis of the equity return requirement, the cost of equity and the recommended allowed return would be significantly higher. Resp. Ex. 3.0, p. 15.

The sample includes every LDC:

1. classified by *Value Line* as a gas distribution utility;
2. with no less than 80% of total assets devoted to gas distribution operations; and,
3. whose Standard & Poor's debt rating is BBB- or higher.

In assessing financial risk, the debt rating agencies focus on a number of financial measures, including, but not limited to, Funds from Operations interest coverage, Funds from Operations to debt, Earnings before Interest and Taxes (EBIT) interest coverage and Debt to Capital. While the capital structure is only one of the quantitative measures that the rating agencies focus on when assessing financial risk and establishing debt ratings, it bears noting that AmerenCILCO's proposed stand-alone utility common equity ratio of 52% falls within the range of actual common equity ratios (based on both total and permanent capital) of the proxy sample of LDCs (Schedule 5), and well within the range of *Value Line*'s forecast common equity ratios for the sample (Schedule 4). AmerenCILCO's Moody's and Standard & Poor's debt ratings are A2 and A- respectively, both with negative trends. By comparison, the median debt ratings for the proxy sample of utilities are A3 and A- respectively. With a common equity ratio in the range maintained by the sample of utilities and similar debt ratings,[5] the cost of equity applicable to the proxy sample can thus be applied to AmerenCILCO. Resp. Ex. 3.0, pp. 15-16.

The equity risk premium test is derived from the basic concept of finance that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity is exposed to greater risk than an investor in bonds, the former requires a premium above bond yields as compensation for the greater risk. The equity risk

[5] S&P's consolidated approach to rating utilities means that, for AmerenCILCO, as well as for the sample of LDCs, its debt ratings reflect the parent's consolidated business and financial risks.

premium test is a measure of the market-related cost of attracting capital, i.e., a return on the market value of the common stock, not the book value. Resp. Ex. 3.0, pp. 3-4.

Ms. McShane used the Capital Asset Pricing Model ("CAPM") and two direct estimates of utility equity risk premiums, the first by reference to historic achieved equity risk premiums for LDCs and the second by reference to forward-looking equity risk premium estimates for LDCs.

The CAPM is a formal equity risk premium model, which specifies that the required return on an equity security is a linear function of the required return on a risk-free investment. In its simplest form, the CAPM posits the following relationship between the required return on the risk-free investment and the required return on an individual equity security (or portfolio of equity securities):

$$R_E = R_F + b_e (R_M - R_F)$$

where,

R_E = Required return on individual equity security
R_F = Risk-free rate
R_M = Required return on the market as a whole
b_e = Beta on individual equity security.

The CAPM relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth). Company-specific risks, according to the CAPM, can be diversified away by investing in a portfolio of securities, and therefore the shareholder requires no compensation to bear those risks. Resp. Ex. 3.0, p. 35.

The non-diversifiable risk is captured in the beta, which, in principle, is a forward-looking (expectational) measure of the volatility of a particular stock or group of stocks, relative to the market. Specifically, the beta is equal to:

$$\frac{\text{Covariance } (R_E, R_M)}{\text{Variance } (R_M)}$$

The variance of the market return is intended to capture the uncertainty related to economic events as they impact the market as a whole. The covariance between the return on a particular stock and that of the market reflects how responsive the required return on an individual security is to changes in events, which also change the required return on the market. Resp. Ex. 3.0, p. 36.

In simplistic terms, the Capital Asset Pricing Model requires determining the equity risk premium required for the market as a whole ("market risk premium"), then adjusting it to account for the risk of the particular security or portfolio of securities using the beta. The result (market risk premium multiplied by beta) is an estimate of the equity risk premium specific to the particular security or portfolio of securities. Resp. Ex. 3.0, p. 36.

The simple CAPM model is a single period model which, if the model were applied rigorously, would entail using a short-term government interest rate as the risk-free rate. However, it is widely recognized that short-term rates are largely the effect of monetary policy and, as such, are administered, rather than market-driven, rates. Hence, most analysts rely on a long-term government yield, which is risk-free in that there is no default risk associated with U.S. Treasury securities. Moreover, reliance on a long-term yield is consistent with the longer-term nature of utility investments. Resp. Ex. 3.0, p. 36.

She utilized the forecast yield on the 10-year Treasury bond as a proxy for the risk-free rate. In principle, a longer-term Treasury should be used, so as to more closely match the duration of the risk-free rate and common equities. However, in 2001 the U.S. Treasury stopped issuing new 30-year bonds. As a result, the yield on existing 30-year Treasuries became a less reliable proxy for the risk free rate. Although the Treasury has announced its intention to once again issue new 30-year debt commencing February 2006, the 10-year Treasury bond remains the benchmark, and is likely to remain so. As a result, her CAPM analysis relies on the benchmark 10-year Treasury yield as the risk-free rate proxy. Resp. Ex. 3.0, p. 37.

While the market risk premium concept is deceptively simple, its quantification is, in principle, quite complex, because the level of the risk premium expected or required by investors is not static; it changes with economic and capital market conditions (particularly with inflation expectations), as well as with investors' willingness to bear risk. Resp. Ex. 3.0, p. 37.

The required market equity risk premium can be developed (1) from an analysis of achieved market risk premiums and (2) from estimates of prospective market risk premiums. With respect to the latter, the discounted cash flow model can be used to estimate the cost of equity, where the expected return is comprised of the dividend yield plus investor expectations of longer-term growth based on prevailing capital market conditions. The estimated market equity risk premiums are obtained by subtracting the corresponding government bond yield from the estimated cost of equity.

The results of the various equity risk premium tests indicate a required equity risk premium of approximately 5.0-6.0% at a 10-year Treasury yield of 5.5%. The resulting market-derived cost of equity is in the range of 10.5-11.5%.

Similar to the DCF result, the 10.5-11.5% cost determined by using variants of the equity risk premium test is a market-derived cost, which measures the return investors expect on the market value of their equity investments. As with the DCF test, the equity risk premium cost rate needs to be adjusted to recognize the disparity between market and book values. At a minimum, the adjustment should permit the utility to recover all flotation costs associated with equity financing, to be in a position to raise equity capital without dilution of book value, and to provide a cushion against unanticipated market conditions. As with the DCF test, a minimum allowance for financing flexibility is 50 basis points. The addition of a 50 basis point allowance for financing flexibility results in a return on equity of 11.0-12.0%.

The equity risk premium tests are all based on market data, and comprise return requirements that apply to market value capital structures. As shown on Schedule 15, an adjustment to the equity risk premium test to account for the higher financial risk between the average market value equity ratio of the sample and the book value capital structure is in the range of 90 to 210 basis points, for a return of approximately 12.5%. Based on the low end of the range of the equity risk premium estimates (5.0%) and a forecast 10-year Treasury of 5.5%, the indicated return is approximately 13.0%.[6]

A fair return is in the range of approximately 11.5-13.0%, where the lower end represents a minimum adjustment for financing flexibility and the upper end of the range represents an adjustment to the market-derived cost of equity to recognize a long-run equilibrium market/book ratio of 1.50. Resp. Ex. 3.0, pp. 37-51.

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[6] $$\frac{1.50\ (10.5\%)}{1 + (.40\ (1.50 - 1.0))} = 13.1\%$$

The comparable earnings test provides a measure of the fair return based on the concept of opportunity cost. Specifically, the test is derived from the premise that capital should not be committed to a venture unless it can earn a return commensurate with that available prospectively in alternative ventures of comparable risk. Since regulation is intended to be a surrogate for competition, the opportunity cost principle entails permitting utilities the opportunity to earn a return commensurate with the levels achievable by competitive firms of similar risk. The comparable earnings test, which measures returns in relation to book value, is the only test that can be directly applied to the equity component of an original cost rate base without an adjustment to correct for the discrepancy between book values and current market values. Resp. Ex. 3.0, pp. 51-52.

The concept that regulation is a surrogate for competition implies that the regulatory application of a fair return to an original cost rate base should result in a value to investors commensurate with that of similar risk competitive ventures. The fact that a return is applied to an original cost rate base does not mean that the original cost of the assets is the appropriate measure of their fair market value. The comparable earnings standard, as well as the principle of fairness, suggests that, if competitive industrial firms of similar risk are able to maintain the value of their assets considerably above book value, the return allowed to utilities should likewise not foreclose them from maintaining the value of their assets as reflected in current stock prices. Resp. Ex. 3.0, p. 52.

Application of the test to utilities would be circular. The achieved returns of utilities are influenced by allowed returns. In contrast, the earnings of competitive firms represent returns available to alternative investments independent of the regulatory process. Resp. Ex. 3.0, p. 52.

The U.S. industrials were selected as follows: The initial universe consisted of all companies actively traded in the U.S. from S&P's Research Insight database in Global Industry Classification Standard (GICS) sectors 20-30. The sectors represented by the GICS codes in this range are: Industrials, Consumer Discretionary and Consumer Staples.[7] The resulting universe contained 2,808 companies. All non-U.S. companies were then removed, leaving 2,497 companies. From this group of 2,497 companies, those with missing or negative common equity during the period 1992-2003 or with 2003 common equity less than $50 million were removed (739 companies remaining). To ensure that low risk companies were selected, all companies with *Value Line* betas of 1.0 or more were removed (384 firms remaining). To remove thinly traded companies, all companies that traded fewer than 125,000 shares in 2003 were eliminated (381 firms remaining). Next, all companies that paid no dividends in any year 1999-2003 were removed (219 firms remaining). Next, those companies whose 1999-2003 returns were greater than ± 1 standard deviation from the average were removed to eliminate companies whose earnings have been chronically depressed or which have been extraordinarily profitable (179 firms remaining). Finally, those companies for which the *Value Line* Safety rank was equal to "4" or "5",[8] and those whose debt is rated non-investment grade, i.e., BB+ or below by Standard & Poor's, were eliminated. The final sample of low risk U.S. industrials is comprised of 139 companies. Resp. Ex. 3.0, pp. 52-53.

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[7] Included in these sectors are major industries such as: Food Retail, Food Distributors, Tobacco, Packaged Foods, Soft Drinks, Distillers, Household Appliances, Aerospace and Defense, Electrical Components & Equipment, Industrial Machinery, Publishing & Printing, Department Stores, and General Merchandise.

[8] *Value Line*'s Safety rank is a measurement of potential risk associated with individual common stocks. The Safety rank is computed by averaging two other *Value Line* indexes – the Price Stability Index and the Financial Strength rating. Safety ranks range from "1" (highest) to "5" (lowest).

There is no legal or economic requirement that the sample of competitive firms must be identical in risk to the regulated company. What is required is the application of an appropriate adjustment to the industrials' returns so that the end result is compatible with the total risk profile of the regulated firm. That adjustment has been made.[9]

Since the objective of regulation is to simulate competition, it is critical that the determination of a fair return explicitly consider the returns achievable by competitive firms on a risk-adjusted basis. This avoids the circularity that a focus on other regulated companies alone entails and ensures that the objective of regulation is achieved.

At the very least, the results of the comparable earnings test should be relied upon as an indicator of whether the market-based test results, as adjusted for the market/book ratio are reasonable. The DCF test and equity risk premium tests as adjusted for a long-run equilibrium market/book ratio of 1.50 indicate returns in the range of 12.0-13.0%. The risk-adjusted comparable earnings test indicates that low risk competitive firms are able to earn returns in a very similar range, 12.75-13.25%. Resp. Ex. 3.0, p. 58.

Staff witness Freetly takes issue with Ms. McShane's conclusions that the recent forecasted three- to five-year growth rates for utilities are low relative to expected long-term growth in the economy as a whole and likely to understate the growth rates that investors expect into perpetuity (that is, the growth rate that is reflected in the stock price). In that regard, she states that past growth rates may be misleading, since they may reflect changes in the fundamental variables that investors do not expect to continue in the future, or fail to capture changes that investors do expect. The Ameren Companies do not disagree that historical actual

[9] Note that the application of the CAPM is effectively a similar exercise, i.e., it requires a relative risk adjustment to the market-based return required for an average risk stock.

growth rates may be misleading as estimates of what investors expect going forward. Resp. Ex. 33.0, p. 2. Ms. MsShane's comments with respect to the level of expected growth for the next three to five years, however, were in reference to the level of growth that analysts had forecast for similar periods during the past 13 years (1993-2005). The point she was making was that, on average, the three- to five-year growth rates had varied around a rate approximately equal to the expected growth in the economy as a whole. Id. Thus, while investors may expect growth for utilities in the relatively short-term to be lower than growth in the economy, the observed pattern of expected three- to five-year growth rates strongly suggests the expected growth rate in perpetuity mirrors the rate of growth in the economy. Changes in variables such as regulation may alter short-term growth expectations, but in the absence of a major shift in economic fundamentals (e.g., inflation, productivity), the long-term inherent growth potential for utilities should remain relatively stable. Id.

Ms. Freetly also contended that the long-term expected growth for utilities must be lower than the growth in the economy as utilities are of lower than average risk, earn lower than average returns, and have below average retention rates. It is clear from Ms. Freetly's own evidence, however, that, at the present time, the expected growth rate for the average stock is well in excess of the rate of growth in the economy. Resp. Ex. 33.0, p. 2. Ms. Freetly stated that the average expected rate of growth for dividend paying stocks in the S&P 500 is 11.3%, or more than twice the expected growth in the economy. ICC Staff Ex. 15.0. If utilities were excluded from the S&P 500 index, the expected growth rate for the remaining dividend paying sectors would be higher than 11.3%. Resp. Ex. 33.0, p. 3. That comparison simply confirms that utilities are expected to grow more slowly than the average stock in the next three to five years,

but provides no basis for concluding that the expected growth for utilities in perpetuity should be less than the rate of economic growth. Id.

Ms. Freetly also states that the market efficiently reflects growth expectations in the stock price and that those expectations need to be reflected in the DCF model whether they are irrationally exuberant or irrationally pessimistic. The question is whether the irrational exuberance or pessimism is for the near-term or the long-term. Resp. Ex. 33.0, p. 3. Since we cannot read investors' minds, we cannot state with any degree of certainty whether the stock price today incorporates the expectation that the three- to five-year growth rate forecasts will continue forever, or the expectation that growth will trend over time to a long-run value. Consequently, estimating the utility cost of equity using both assumptions is a reasonable means of approximating long-term growth expectations. Id.

Ms. Freetly claims that Ms. McShane's comparison of Staff's DCF estimate to utility bond yields as a means of testing its reasonableness is misleading on two counts; first because she is not recommending a return equal to the 9.11% DCF cost, and second, because a comparison with Baa rated utility bond yields is not appropriate since she is recommending returns that, in her view, are compatible with the achievement of debt ratings higher than Baa. Ms. McShane's conclusions in this regard were in specific reference to the results of Staff's DCF test, given the growth rates Ms. Freetly had used, and to whether the results of that specific test were reasonable in light of historic relationships between allowed returns and yields on utility bonds in the same rating category as her sample (median S&P debt rating of BBB+). In this context, the allowed returns were used as a proxy for the DCF cost, on the grounds that the DCF test has historically been the principal test used by state regulators in setting allowed ROEs. Resp. Ex. 33.0, p. 4.

Ms. Freetly claims that there is nothing inherently superior about the *Value Line* betas as compared to her regression betas, and states that, in contrast to earlier time periods, when her raw regression beta was unusually low, her current raw beta is more typical. The term "typical," however, assumes that the "true" beta is static. Exhibit 33.0, Schedule 1 demonstrates that the *Value Line* betas for Ms. Freetly's sample have been rising over time.[10] The betas are considerably higher for the most recent period available (median of 0.90) than the 0.75 level observed prior to the anomalous market bubble and bust period (1998-2002) during which utility betas were unusually low. The rising betas of these utilities demonstrate that the accuracy of Ms. Freetly's regression betas cannot be tested against what has been "typical". The fact remains that calculating betas using more observations (i.e., *Value Line*'s weekly observations versus Ms. Freetly's monthly observations) will improve the fit of the regression line. Resp. Ex. 33.0, pp. 4-5.

Mr. Gorman makes a similar argument to that of Ms. Freetly regarding the growth prospects of utilities relative to the S&P 500. He simply shows that the growth for companies that pay out more in dividends than those that do not would be expected to achieve lower growth rates in the near future than those that retain more. We have no disagreement with this basic proposition. Ms. McShane has not claimed, as Mr. Gorman suggests, that utilities can grow as fast the growth rates currently anticipated for the S&P 500. Over the next three to five years, the expected growth rates for the companies in the S&P 500, who are currently paying out about 30% of earnings, are much higher than the expected growth in the economy, as indicated in Ms. Freetly's testimony. Consistent with the higher expected growth is a much lower dividend yield

[10] Exhibit 33.0, Schedule 1 provides a history of the *Value Line* betas of Ms. Freetly's sample.

for the S&P 500 than for utilities. When the growth prospects for the companies that currently make up the S&P 500 decline (and gradually trend toward the growth in the economy and potentially lower when they reach the stage of decline), they will begin to pay out a higher proportion of their earnings in dividends and exhibit higher dividend yields. There is no inconsistency between that proposition and the expectation that long-run growth prospects of the mature utility industries mirror the long-run growth potential in the economy as a whole. Resp. Ex. 33.0, pp. 6-7.

Mr. Gorman takes issue with a critique of his risk premium test in which he estimates the annual average differential between allowed returns and bond yields over the period 1986-2005 rather than a more recent period, on the grounds that inflation impacts both stock and bond yields and valuations.

Ms. McShane agreed that inflation impacts both. The issue is whether the fear of inflation impacts both equally. If inflation rises above expected levels, bond investors will be impacted more negatively, since they are locked-in at the rate at which they invested. If there is a strong fear of unanticipated inflation, bond investors will require an additional premium above the expected rate of inflation (a lock-in premium). Since equities are a better hedge against unanticipated inflation, equity investors will not demand a lock-in premium of the same magnitude. During periods when the fear of unanticipated inflation is high, and the lock-premium in bond yields is also high, the equity risk premium will be lower. When the fear of unanticipated inflation dissipates, the equity risk premium will expand. Resp. Ex. 33.0, pp. 7-8.

The existence of a higher lock-in premium during the earlier years of Mr. Gorman's analysis can be discerned by comparing real dividend yields and real bond yields from 1986-1995 and from 1996-2005. During 1986-1995, the average real utility dividend yield was

3.1% compared to the real Treasury bond yield of 4.0%, where the real yield was estimated as the nominal yield in each year minus the forecast long-term rate of CPI inflation.[11] By comparison, during 1996-2005, the real utility dividend yield had not declined at all from its average 1986-1995 level, while the real Treasury bond yield had declined by .9% to 3.1% (Exhibit 33.0, Schedule 3). The larger decline in the real bond yield is a strong indicator of a reduction in the relative risk of Treasury bonds and an increase in the equity risk premium. Using the longer 1986-2005 period to measure the differential between allowed returns and bond yields masks the change in the equity risk premium that occurred as bond investors became increasingly comfortable that inflation would not reignite to levels that had been experienced in the 1970s and early to mid-1980s. Resp. Ex. 33.0, p. 8.

Mr. Cuthbert argued that Ms. McShane's results are overstated because you did not conduct any risk premium analyses relative to corporate bond yields. Mr. Cuthbert conducted one test using corporate bond yields. The result was higher than his DCF results and lower than his CAPM results. The simple average of his DCF, equity risk premium and CAPM results for his comparable sample as summarized on RWC-6 is 9.7%. Excluding the risk premium test using corporate bond yields, the simple average of the DCF and CAPM tests is lower, at 9.65%. Based on Mr. Cuthbert's own tests, ignoring any problems with their application, there is no basis to conclude that including a test using corporate bond yields would produce a lower recommended return. Resp. Ex. 33.0, p. 15.

Mr. Bodmer claims that Ms. McShane's real argument is that this Commission should grant the Ameren utilities a similar return to that which has been allowed by other state

[11] From *Blue Chip Economic Indicators'* bi-annual long-term forecasts during the year that corresponds to the actual bond and utility dividend yields as presented in MPG-R1. See Exhibit 33.0, Schedule 3.

commissions. It goes without saying that the estimation of the cost of equity and a fair return should be independent of what other regulators allow. Nevertheless, the national average can be interpreted as a consensus assessment of the expert testimony that has been proffered by a wide range of stakeholders under capital market conditions that are similar to those prevailing. As one regulatory commission correctly observed in a recent decision approving an 11.0% ROE, a return on equity finding should not mindlessly mirror the national average. However, the regulatory commission also pointed out that the national average is an indicator of the capital market in which the utility will have to compete for necessary capital. Similarly, the national average is an indicator of the reasonableness of the return recommended. It is not necessary to address each aspect of Mr. Bodmer's testimony to conclude that his recommended return of "no greater than 8%" simply is not indicative of the capital market in which the Ameren utilities will have to compete for capital. Resp. Ex. 33.0, p. 16.

Mr. Bodmer also claims that the high market/book ratios of utilities are an indication that the allowed returns should be lower than they are. Mr. Bodmer believes that the market/book ratio of utilities should be 1.0. There are multiple reasons this would not be the case even if such an outcome were fair and reasonable.[12] These reasons include the fact that market price reflects future earnings expectations, expected earnings from unregulated operations, the fact that the reported assets are an imperfect measure of the base upon which utilities are allowed to earn a return, and the value that investors place on the stability of dividends. Moreover, the level of the market/book ratios of utilities is a relative concept, and

[12] See Exhibit 3.0, lines 538-545 for discussion of why a market/book ratio of 1.0 for a utility is inconsistent in principle with the competitive model that regulation is intended to emulate.

should be judged relative to the tenor of the market as a whole. Over the past 10 years (1996-2005), the market/book ratio of the S&P 500 has averaged 3.6 times; it is currently 3.0 times (*Barron's*, June 26, 2006). Over the same decade, the market/book ratio of all the utilities that are included in the proxy samples of Ms. Freetly, Mr. Gorman, Mr. Cuthbert and myself averaged 1.6 times, less than half the level of the equity market composite (which includes utilities); the current median market/book ratio for these same utilities is also 1.6 times; See Exhibit 33.0, Schedule 5. Relative to the market as a whole, the market/book ratios of the utilities are quite modest and provide no basis for concluding that allowed returns have been too high. Resp. Ex. 33.0, p. 17.

Mr. Cuthbert claims that Ms. McShane's sample of gas distribution utilities is of higher risk than a sample of electric utilities. To support his view that gas utilities are more risky than electric utilities, Mr. Cuthbert cites a *Value Line* article (RWC-7) which refers to the impact of rising gas prices on gas utilities. Mr. Cuthbert implies that the article concludes gas utilities are more risky than electric utilities, which it does not. One risk factor cannot be used to conclude that gas utilities are more risky than electric utilities. The various risk statistics of Mr. Cuthbert's and my samples demonstrate objectively and quantitatively that the gas utilities I have relied upon are less risky than his sample of electric utilities (Exhibit 13.0, Table 4). Mr. Gorman also uses a sample of gas utilities; there is no objective evidence that his sample of gas distributors is riskier than his electric utility sample. Ms. Freetly includes gas utilities in her sample; there is no objective evidence that the gas distributors in the sample are riskier than the electric utilities in the sample. Resp. Ex. 33.0, p. 11.

The Ameren Companies recognize that the Commission frequently, if not typically, adopts the Staff's recommended ROE. If that is again the case, in this proceeding, the

Ameren Companies request that the Commission consider one aspect of the Staff's recommendation.

Staff witness Freetly recommended returns on equity of 9.9%, 9.85% and 9.96% for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. She arrived at her recommendation by first estimating the investor required return for her utility sample at 10.25%. She then adjusted the result downward for each of the Ameren Companies to reflect her belief that each of the Ameren Companies is lower in risk relative to the sample. Tr. 994 (Freetly).

Ms. Freetly determined that the Ameren Companies are of lower risk by developing "implied forward looking credit ratings" for each Company and comparing those to the average credit ratings of the sample. ICC Staff Ex. 15.0, p. 6; Tr. 994-95 (Freetly). She developed those "implied ratings" by using values for certain benchmark financial ratios that result from the application of the Staff's revenue requirement. Tr. at 995 (Freetly). In other words, she factored in the presumed effect of the revenue increases recommended by the Staff in this case on the Ameren Companies' future credit ratings. Tr. at 997 (Freetly).

A principle problem with Ms. Freetly's analysis is that she assumes that the Companies will have higher credit ratings than they currently have. That is, she assumes that the Companies' credit ratings will be going up, at a time when they are going down for reasons that have nothing to do with the issues before the Commission in this case.

The day before Ms. Freetly took the stand, Moody's issued a release regarding the Ameren Companies' credit ratings, in which it downgraded AmerenCIPS and AmerenCILCO. Ameren Freetly Cross Ex. 1. As a result of those downgrades, AmerenCILCO's rating is four notches below the level assumed by Ms. Freetly, and AmerenCIPS is six notches below her

assumed level. Tr. at 999 (Freetly). AmerenIP was unchanged, but is still four notches below Ms. Freetly's assumed level. Tr. at 1000 (Freetly).

There is nothing in the record to suggest that the wide gulf between the current ratings and Ms. Freetly's assumed ratings will be bridged by the final order in this case. Moody's downgraded AmerenCIPS and AmerenCILCO, and held AmerenIP just one notch above sub-investment grade, due to "a difficult political and regulatory environment for electric utilities in the state of Illinois," related to rate increases for "purchased power costs." Ameren Freetly Cross Ex. 1. Further, Moody's indicated its expectation that "the outcome will involve a material regulatory deferral of higher procurement costs." Id. Hence, the Ameren Companies' ratings are moving the opposite direction of Ms. Freetly's assumption due to factors that are outside the scope of this proceeding and which the final order in this case will not and cannot address.

Moreover, even if Moody's had not downgraded the Companies, there is still no basis for Ms. Freetly's conclusions regarding the Companies' prospective ratings. Mr. Nickloy explained why Staff's recommendation improperly assumes specific credit ratings. In its 2004 publication providing revised financial guidelines for U.S. utilities (*New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised*, published June 1, 2004), S&P stated, that these financial guidelines represent three principal ratios that S&P uses as an "integral part" of evaluating the credit quality of U.S. utility and power companies. Resp. Ex. 14.0, p. 2. Thus, while these ratios are certainly important, S&P clearly indicates that these measures are only a *part* of S&P's *evaluation*. These measures do not constitute anything even close to the *entirety* of their analysis. They are used as part of an *evaluation*, i.e. an analysis or assessment, of the credit quality of the subject entity. Taken together, this means the

ratios are used in the context of an overall, comprehensive credit analysis including, as we know, both quantitative factors such as these and other ratios along with a variety of qualitative factors. This does not mean that simply by achieving one or more of these ratio guidelines (especially given the leverage ratio) for a given rating level that any given rating will automatically be assigned. It also noteworthy that S&P has characterized these measures as "guidelines." Id. at 2-3.

It is not appropriate then to use S&P's published financial ratio guidelines as the sole basis for the reasonableness of a recommendation for a given cost of equity, weighted average cost of capital, capital structure (including any hypothetical capital structure) and/or revenue requirement, for a number of reasons:

(1) Although financial ratios are important in any evaluation of an entity's credit quality, ratios alone do not define the analysis, especially if only considering a single ratio such as leverage (debt to capital). In the S&P publication referenced above, S&P includes the following language immediately before and immediately after the table listing their ratio guidelines:

> "It is important to emphasize that these metrics are *only guidelines* associated with *expectations* for various rating levels. Although credit ratio analysis is an important part of the ratings process, these three statistics [FFO interest coverage, FFO/total debt, and debt/capital] are by no means the only critical financial measures that [S&P] uses in its analytical process." (Emphasis added.)
>
> And,
>
> "Again, *rating analysis is not driven solely by these financial ratios*, nor has it ever been. In fact, [these revised financial guidelines] reinforce the analytical framework whereby other factors can outweigh the achievement of otherwise acceptable financial ratios." (Emphasis added.)

We simply cannot ignore what the rating agencies have said here – the ratio guidelines are not definitive in terms of the assignment of ratings.

> (2) The ratio guidelines at issue here are only those published by S&P. The S&P guidelines would not be instructive or helpful in attempting to presuppose any ratings assigned by Moody's based on a similar analysis.
>
> (3) The rating agencies are the arbiters of credit ratings. Any analysis performed by others in an attempt to support or assume a given rating can be dangerously misleading. This would be especially true given the qualitative factors which are important to the rating agencies at the time they are reviewing or assigning ratings. The specific factors, and the relative importance or weighting those factors receive in the rating agencies' analyses are known with certainty only by the agencies.
>
> (4) As part of their ratio analysis, the rating agencies typically make certain adjustments. For example, S&P and Moody's remove the debt related to AmerenIP's transitional funding trust notes ("TFNs") along with the cash flow dedicated to service that debt. S&P also imputes a debt equivalent for AmerenIP's power purchase agreement with Dynegy along with related imputed interest.

Resp. Ex. 14.0, pp. 3-4.

These adjustments can have a meaningful impact on the calculation of financial ratios. The cash flow adjustment to remove the effects of AmerenIP's TFNs results in a reduction of annual cash flow of at least $86 million. This cash flow adjustment has a meaningful negative impact on any metric that uses cash flow as an input (such as interest coverage and cash flow/debt). Mr. Nickloy explained that the Ameren Companies know from discussions with S&P that the imputed debt equivalent related to its purchased power arrangement with Dynegy (a 2.25-year arrangement at the time of the closing of Ameren's acquisition of AmerenIP) was around $600 million. S&P recognized that notwithstanding the relatively short tenor of this specific power supply agreement, AmerenIP's need to continue to obtain its power supply requirements from third parties would continue well beyond the maturity date of that agreement. Annual interest related to this debt imputation was based on an interest rate of 10%. Given the potential magnitude of these adjustments, any ratio analysis must reflect such adjustments in the same manner as performed by the rating agencies. The purchased power

debt imputation issue could remain significant for AmerenIP and become a much bigger issue for AmerenCIPS and AmerenCILCO once new power supply arrangements are entered into for periods post 2006. Resp. Ex. 14.0, p. 5.

On balance, with respect to being consistent with a given rating, there certainly would be reason for concern if an entity's ratios were to decline or fall out of the S&P ratio guideline ranges for that rating. However, to reiterate, it would be unwarranted and inappropriate to assume that simply because that entity's metrics fall within the guideline ranges that the related rating will be the result. Resp. Ex. 14.0, p. 5.

Even if Ms. Freetly could accurately predict credit ratings, her adjustment would still be unfounded. The Ameren Companies agree with Ms. Freetly that, in principle, there is a direct relationship between risk and required return. However, Ms. Freetly has not demonstrated that, in practice, the DCF test is accurate enough to distinguish between samples of somewhat different levels of investment risk. Ms. Freetly made the unwarranted assumption that the DCF cost of equity that she estimated for her sample is a completely accurate measure of the cost of equity for that risk level. The implication of that assumption is that, had she actually measured the DCF cost of equity for a lower risk utility sample, e.g. a sample whose average debt rating was AA, the DCF estimates would have been lower than those of her sample by approximately 40 basis points. Ms. McShane's comparison of the DCF costs of Mr. Gorman's two samples demonstrated that is not necessarily the case, as the estimated DCF cost for his gas sample was 30 basis points higher than the DCF cost for his electric sample. The electric utility sample is at least as risky, and potentially more risky, than his gas sample.

To further illustrate this point, Ms. McShane took all the utilities that were in the utility samples of the five direct cost of capital testimonies filed in this proceeding, and

calculated their DCF cost using the annual constant growth DCF model, the stock price as of April 4, 2006 (the same date used by Ms. Freetly in her DCF test), the most recent dividend paid prior to that date, and the I/B/E/S consensus forecast of earnings growth for each utility at the end of March 2006. She then sorted the utilities by their April 7, 2006 S&P bond rating. Next, she calculated the mean and median DCF costs for all of the utilities with a debt rating of BBB-, BBB, and BBB+, and the mean and median debt costs of all of the utilities with a debt rating of A-, A, or A+. The mean and median DCF costs for the utilities rated in the BBB category were 9.5% and 8.7% respectively; the mean and median DCF costs for the utilities with ratings in the A category were 9.7% and 9.1% respectively (See Exhibit 33.0, Schedule 2). In other words, the estimated DCF costs were higher for the less risky companies. Thus Ms. Freetly's deduction from her sample's DCF cost of equity for the alleged relatively lower risk of the Ameren utilities cannot be empirically justified. Resp. Ex. 33.0, p. 6.

G. Other

H. Recommended Return on Rate Base

The Ameren Companies' recommended returns on rate base are: AmerenCILCO, 8.848%; AmerenCIPS, 8.507%; and AmereIP, 8.946%.

III. RATE DESIGN

A. Below is a Summary of the Uuncontested/Settled Issues.

- The Ameren Companies accept Staff witness Greg Rockrohr's proposal in concept with regard to the prior AmerenCIPS incentive to have customers install their own transformers. The Ameren Companies will provide a separate, lower, customer charge for those customers who are metered on the primary side of customer-owned transformers, so long as the proposed test or billing units are allowed to be adjusted. (Resp. Ex. 20.0, pp.15-16). These customers will be assessed the Customer and Meter Charges as if they were metered on the lower voltage side

of transformation. (Resp. Ex. 41.0, p.19). The specific steps to mitigate these charges are identified at Resp.' Exhibit 20.0, pages 16-17.

- Acceptance of Staff's proposal to adjust rates if the final revenue requirement is different than proposed, where if the difference in the Customer and Meter Charges is less than a relatively small charge of 25 cents per month for DS-1 customers, no adjustment is made; if the charge is greater than 25 cents, adjust Customer and Meter charges by combined Ameren Companies' percentage change in total revenue requirement, and the remaining revenue requirement is recovered through a percentage adjustment to various Distribution Delivery Charges applicable to the customer classes at each Ameren Company. (Resp. Ex. 41.0, p.18).

- Acceptance of Staff's proposed language to be inserted in DS-1 to ensure that existing customers receiving three-phase service will not have to pay an Excess Facilities charge. (Resp. Ex. 20.0, pp.17-18).

- Acceptance of Staff's proposed language change to Section 14.D of the Customer Terms and Conditions. (Resp. Ex. 20.0, pp.38).

- Acceptance of Staff witness Griffin's proposed changes to the Qualifying Solid Waste Energy Facility provisions of Rider QF (Resp. Ex. 20.0, p.34).

- The Ameren Companies agreed with Staff to meet certain criteria, should they implement a new or revised charge under Local Government Fee and Adjustment tariffs. These criteria include: a) notify Commission; b) receive authorization to implement; c) include proper documentation; d) include supporting calculations; and e) include a listing of fees by local government authority similar to those in Municipal Tax Additions. (Resp. Ex.31, p.12).

- Acceptance of the CNE/PES position, that the Ameren Companies provide a schedule similar to Schedule 10.10 on the Ameren website, explaining the translation of the existing schedule of rates. (Resp. Ex. 20.0, p.41).

- Acceptance of the IIEC recommendation, that the Ameren Companies provide projections of hourly system load figures at least on a day-ahead basis and to post a day-ahead forecast of hourly loss multipliers for each voltage level. This will serve to allow suppliers the opportunity to minimize settlements associated with errors in distribution loss calculations. (Resp. Ex. 41.0, pp.23-24).

- Agreement by the Ameren Companies to eliminate the DASR Submission Fee and Standard Switching Fee. (Resp. Ex. 41.0, p.25).

- Agreement to implement certain EDI transactions. (Resp. Ex. 49.0, pp.10-11).

- Agreement to include 24 months of customer billing data on Ameren.com. (Resp. Ex. 48.0, p.4).

- The Ameren Companies and the AG reached an understanding with regard to the claim that the franchise expense was being duplicated. AG witness Effron acknowledges that the Ameren Companies have adjusted their revenues to reflect what the revenue would be if free service was billed at tariff rates as explained by Ameren Company witness Jones. (See AG Ex. 3.0, pp.10-11; Resp. Ex. 20, pp.38-39).

- Revisions to Rider TS per the request of CNE/PES. (Resp. Ex. 20.0, p.29).

- Calculated Cash Working Capital factors for each of the Ameren Companies, to be reset in subsequent delivery service rate cases. (Ameren Ex. 6.0S, p.3).

B. Customer Class Issues

1. General Discussion

The Ameren Companies are proposing to use five service classifications. DS-1 is for all Residential Service; DS-2 is Small General Service for all non-residential up to 150 kW; DS-3 is General Service for all non-residential, from 150 kW up to 1,000 kW; DS-4 is Large General Service for all non-residential 1,000 kW and greater; and DS-

5 is for Lighting Service. (AmerenCILCO Ex. 10.0, p.4, AmerenCIPS Ex. 10.0, p.4 and AmerenIP Ex. 10.0, p.4). No party took issue with the new classes as being proposed, except as to DS-3 as addressed below. Staff witness Cheri Harden agreed the rate classifications are appropriate as they are primarily differentiated by customer usage and voltage level at which customers are served. (ICC Staff Ex. 7.0, p.5).

2. Wal-Mart Recommendation Regarding Separate Rate Classes

Wal-Mart witness James Selecky proposed that the DS-3 class be separated into two separate rate classes, one for customers with demands ranging from 150 kW up to 400 kW and another for customers with demands of 400 kW up to 1,000 kW. Mr. Selecky's justification for the sub-classes is that the DS-3 service classification is too broad, relying upon testimony provided in the Commonwealth Edison procurement case. (Wal-Mart Ex. 1.0, p.13).

There are a number of reasons why the Wal-Mart proposal should be rejected, at least at this time. Creating a new rate class involves a study of the class load characteristics to ensure that a separate rate class is in fact warranted. Neither Mr. Selecky nor the Ameren Companies have created such a study and, indeed, Mr. Selecky relies upon information from the Commonwealth Edison proceeding. Mr. Selecky knowing full well that such a study is required, recommended the Commission require the Ameren Companies to provide the cost of service study in this case, which has not occurred. (Wal-Mart Ex. 1.0, p.14). Such a study was not provided as Wal-Mart failed to properly place the issue before the Commission.

Next, for customers with demand over 400 kW, the Ameren Companies intend to install interval metering which will be accomplished within the next two years.

This metering will be helpful should there be decision to create the sub-classes. Mr. Selecky also recognizes this as a potential obstacle to creating the sub-classes. (Wal-Mart Ex. 1.0, p.14).

Mr. Jones also observed that without the benefit of further analysis or study, creating sub-classes in this proceeding would result in revenue responsibilities amongst the sub-classes that are simply unknown. (Resp. Ex. 20.0, p.4). Meaning, there could be an undue shifting of revenue responsibilities absent the appropriate data.

In conclusion, while the Ameren Companies are open to the notion of creating sub-classes as suggested by Wal-Mart, appropriate study and consideration with the requisite data and information is not yet at hand. Until such time as interval metering is in place, and the necessary data by which to ascertain the appropriateness of creating sub-classes is available, creating sub-classes at this time is premature. Therefore, there should be no mandate in this proceeding to create the sub-classes.

C. Cost of Service Issues

1. Segregation and accounting for delivery service and generation-related uncollectible expenses

The Ameren Companies proposed that the recovery of uncollectible expenses be consistent with the method as proposed by the Ameren Companies in their competitive power procurement cases. The proposal involves the establishment of an uncollectible expense factor based on the relative relationship between total uncollectible expenses to the total bundled revenue amounts. This factor is then applied to the BGS price to account for the expected level of uncollectible BGS bill amounts and to the Transmission Service expenses to account for the expected level of uncollectible Rider

TS bill amounts. The Rider BGS and Rider TS billings for all customers receiving power supply from the Ameren Companies will include an amount to reflect the Ameren Companies' uncollectible experience. (See AmerenIP Ex. 8.0, pp.6-7).

Mr. Cooper explained a fair and equitable segregation of uncollectible expense can be resolved in the rate making process and noted further that both the Ameren Companies and Staff witness Ebrey had developed similar approaches, in developing the appropriate level of uncollectible expense associated with the provision of delivery services. An uncollectible "factor" is developed for each customer class, and the effect of the factor is to designate a certain amount of uncollectible expense associated with the provision of delivery services only. (Resp. Ex. 39.0, pp.7-8).

Mr. Stafford understood Ms. Ebrey's recommendation to be applying the same uncollectibles rate to the SPA as applied to base rate revenues, with the further understanding that base rate revenues be equivalent to delivery service revenues as established in this proceeding and subsequent delivery service rate cases. The derivation of the electric delivery service portion of Uncollectibles is a percent based upon test year Uncollectibles divided by electric distribution, transmission, and power supply revenue. (Ameren Ex. 6.05, p.3). The same uncollectibles rate would be used for the Uncollectibles Factor Growth-Up recovered through Rider MV, as well, and reset in later rate cases (Resp. Ex. 36.0, p.42).

In summary, while the Ameren Companies do not believe this is a disputed issue, to the extent that is not the case, we recommend the Commission adopt this approach.

2. Development of Meter Costs v. Customer Costs

One of the key rate design proposals being made, are uniform Meter and Customer charges. (AmerenIP Ex.10.0, pp.8-11). Initially Staff expressed concern over the difference in meter costs and meter revenue being recovered by unbundled Meter charges. (ICC Staff Ex. 8.0, pp.3-5). In rebuttal, Staff witness Mike Luth accepted the Ameren Companies' explanation, and agreed the cost structure was not an impediment to a meter service provider wanting to provide such service. Mr. Luth, though, raised the question about the percentage of costs in meter-related accounts recovered through the meter charge in the various rate classes, noting the percentage of meter revenues versus meter costs is relatively low for DS-3 and DS-4 as compared to the percentage for DS-1 and DS-2. (ICC Staff Ex.19, p.3).

Mr. Jones explained and justified why percentage differences are expected. Because most DS-1 and DS-2 customers are metered at a secondary voltage, and the more costly current transformers ("CTs") and potential transformers ("PTs") are not needed and where such transformers are needed for the DS-3 and DS-4 customers, it logically follows that the percentage of meter revenue to meter costs would be relatively low for the DS-3 and DS-4 customers. Stated differently, very few DS-1 and DS-2 customers require CTs and PTs; therefore, there would be a low percentage of costs involved. (Resp. Ex. 41.0, p.17). DS-3 and DS-4 customers are being served at higher voltages and the cost of CTs and PTs becomes higher for each higher level of line voltage reduction required. Mr. Difani concluded that the transformer costs can range from 30 or 40 times the cost of the meter which results in the differences between meter costs and customer charges as questioned by Staff witness Luth. (Resp. Ex. 40.0, p.6-7).

3. NCP vs. A&P

Staff had no objection to the use of the class costs of service studies for allocation purposes, which relies upon the non-coincident peak (NCP) method. In contrast, CUB witness Thomas proposed the use of the Average & Peak ("A&P") allocation method. The use of the A&P method is opposed by both the Ameren Companies as well as the IIEC.

CUB witness Thomas advocated a number of reasons for moving away from the traditional NCP method that is the basis for the Ameren Companies' cost of service method. He suggested this was the first Ameren Company distribution only rate case to determine residential delivery service rates. In this regard, Mr. Thomas is absolutely wrong. The Commission has set rates for delivery service customers since 1999 for all three Ameren Companies. In each of those proceedings the Commission accepted the NCP allocation method. Later, in ICC Docket Nos. 01-0432, 00-0802, and 01-0637, the Commission approved delivery service rates for residential customers, as well as the other customer classes, and again the Commission approved the use of the NCP allocation method. (Resp. Ex. 40.0, p.2).

At the heart of the CUB proposal is its failed understanding as to how the distribution system is designed. CUB witness Thomas contends that the demands imposed by ratepayers throughout the year justify the use of the A&P allocation of distribution demand facilities. In reality, the distribution system must be capable of delivering electricity to each customer and be sized adequately for the maximum demand of that customer or group of customers. Accordingly, the allocation of the distribution system costs should be based upon a combination of individual or customer group non-coincident peak demands. (Resp. Ex. 19.0, p.5).

Further, the A&P method allocates cost not based on the "average" use of the distribution system, but also the usage by customer classes at the time of peak, resulting in a double counting of class demands. This is so because the average demand is also counted as part of the peak demand. (Resp. Ex. 40.0, pp.3-4).

The A&P approach relies heavily on energy usage, a variable allocator, to allocate fixed distribution costs. Such an approach is counter intuitive to the fact that maximum demand is a significant factor in the design and construction of utilities' distribution system. Indeed, the proof of the A&P allocators' over-emphasis on energy usage as a driver in the allocation process was demonstrated by examples provided by Mr. Difani. In those examples, even though each class required the same amount of investment, the A&P allocation would allocate substantially less to one class as compared to the other. (Resp. Ex. 19.0, pp.6-7).

Mr. Thomas also defends the A&P allocation method by referring to a prior Commission gas case. Mr. Difani explained that while there are similarities between the natural gas and electric distribution systems in concept, there are also material differences. For example, demands on electric systems vary significantly hour by hour, and the coincident peak is described as that use in one hour. For gas systems, the coincident peak is described in terms of a daily peak. Also, electric systems are considered to be "on-demand", that is, there is no storage system for electric power and energy and power supply is drawn and taken by customers as it is being generated. In contrast, gas can be stored underground or by another form of storage which is called "line packing". (Resp. Ex. 40.0, pp.4-5).

Particularly troubling is the failed attempt of the CUB analysis in demonstrating the cost impact associated with the A&P allocation proposal. There is no doubt the net effect of the A&P allocation is to re-distribute more costs to the non-residential customers. But what the Commission cannot know from the CUB analysis is how much is being re-distributed. CUB Exhibit 4.02 was an update to CUB Exhibit 2.03. Mr. Thomas testified that CUB Exhibit 2.03 explains the results of modifying the Ameren Companies' cost of service study by using his proposed A&P method. He states unequivocally, "… the use of the A&P allocators tends to distribute more costs to commercial and industrial customers and fewer costs to residential customers". (CUB Ex. 2.0, p.14). Whichever allocation method is used, the revenues to be recovered by the Ameren Companies should be the same – to this there is no dispute. Yet, an examination of, for example, Schedule 4.01 (AmerenCILCO Proposed) with regard to AmerenCILCO shows that under the NCP method AmerenCILCO will recover $138,184,000 yet under the A&P method AmerenCILCO will recover $125,853,000. (Tr. at 965-970). These discrepancies run through the other Schedules 4.01 for AmerenCIPS and AmerenIP as well. (Tr. at 965-970).

When challenged about these discrepancies, Mr. Thomas then claimed the schedules were only for illustration purposes and not intended to form a correct allocation of costs. (Tr. at 973). Mr. Thomas never did take issue with the claim that the exhibits were in error and when asked whether because of the magnitude of the error, one could discern the impact of this proposal, he could only respond that he would have to further review his analysis. (Tr. at 973).

In conclusion, there has been no valid demonstration that the Commission should abandon the use of the NCP method for purposes of allocating costs amongst the customer classes. Further, there is every reason based on the record in this proceeding to thoroughly reject the A&P allocation method. Not only is the A&P method inappropriate for allocating fixed distribution system costs because of its undue reliance on energy usage, but the fact remains this Commission cannot know the full impact of using the A&P allocation method, in terms of the amount of costs that would otherwise be recovered from non-residential customers.

D. Inter-Class Allocation Issues

1. Allocation methodology

The Ameren Companies presented a traditional embedded class cost of service study that is used to determine for each rate class cost based responsibility of the level of revenues necessary to meet the Ameren Companies' operating and maintenance expenses, depreciation provisions applicable to their investment in utility plant, property taxes, income and other taxes, and the fair rate of return on utility rate base. The Ameren Companies' class distribution allocation methods are consistent with the Commission's recent rulings in Docket Nos. 01-0637, 00-0802, and 01-0432, for AmerenCILCO, AmerenCIPS and AmerenIP, respectively. (See AmerenCILCO Ex. 9.0, p.5).

The Ameren Companies used a two step criteria class revenue requirement methodology, to modify the proposed delivery service rates set at the equalized rate of return, for each Ameren Company. First, the DS-1 through DS-3 rate classes were targeted to receive an equal percent revenue change from existing to rebundled service. This had the effect of reducing the DS-1 revenue requirement and increasing the DS-2

and DS-3 revenue requirement. The second step was to ensure that the DS-4 class would receive at least a 5% increase. Originally, this second step would only have applied to AmerenCILCO. (AmerenCILCO Ex. 10.0, pp.5-6). However, a correction to the cost of service study effectively eliminated the second step and it is no longer at issue.

a. Staff Position

Staff witness Harden explained the Ameren Companies have to re-distribute a portion of the class equalized revenue requirement in order to lessen the impact on the customer's total bill. As a result, the proposed increase for the DS-1 through DS-3 classes is an average increase of 15.56% for AmerenIP customers. For the AmerenCIPS' customers in the DS-1 through DS-3 rate classes, they receive an average of 2.78% increase. (ICC Staff Ex. 18.0, p.3). Where Staff differs with the Ameren Companies, is with respect to the revenue allocation methodology affecting AmerenCILCO. Ms. Harden recommended that the DS-2 rate increase should increase from 2.97% to 5.94%, and that the remaining revenue requirement should be recovered from the DS-3 customers. By this adjustment, Staff intends to minimize or limit the rate impact for the DS-2 class. (ICC Staff Ex. 7.0, p.8).

Ameren witness Jones disagreed because limiting the DS-2 rate class to only a 4.51% increase would create an undue revenue deficiency of more than $6.6 million, assuming full recovery of the requested revenue requirement. The increase to the DS-3 class would more than double, increasing from 13.02% to more than 26%. (Resp. Ex. 41.0, p.3). Rather than accept the Staff position, the Commission should affirm the Ameren Companies' treatment of the AmerenCILCO DS-2 and DS-3 classes.

In the end, the DS-3 revenue requirements should be close to the level that will produce an equalized rate of return for the class. (Resp. Ex. 20.0, p.8).

b. Kroger Position

Kroger witness Kevin Higgins testified that all distribution delivery rates should be based on cost of service, with an equalized rate of return for each class. He opined that the DS-3 and DS- 4 rates be set at cost. (Kroger Ex. 1.0, p.4) As explained elsewhere, in its direct case AmerenCILCO's DS-4 class would have been subject to a 5% minimum rate increase floor, however, there was a correction in the class cost of service in the rebuttal case such that the DS-4 class will now receive an increase greater than 5%. Accordingly, the 5% minimum threshold is no longer applicable to AmerenCILCO.

The revised cost of service study also showed a rate decrease for the AmerenCIPS DS-4 customers, which then could have been subject to the 5% minimum rate increase criteria. However, because the increase to the other AmerenCIPS' rate classes is no more than 14% as compared to the projected increases for the other AmerenCILCO delivery service rate classes, the Ameren Companies concluded there was no further need to hold the DS-4 class to a minimum increase threshold. Therefore, the DS-4 rates will be set at cost of service. (Resp. Ex. 20.0, pp. 5-6). This, then, alleviates Mr. Higgins, Mr. Selecky, and IIEC witness Robert Stephens' concerns as to this issue.

Mr. Higgins also proposed a common Distribution Delivery Charge for DS-3 and DS-4 based on their joint cost of service. He recommends a common demand charge that applies to both DS-3 and DS-4 customers. (Kroger Ex. 1.0, p.3).

Mr. Jones testified that while the Kroger proposal is consistent with the long term goal of establishing cost based rates, to do so at this time would result in the DS-4 charges increasing to an unacceptable level. For example, accepting the Kroger position would require an AmerenIP DS-4 increase to about 415%. Instead, the better choice would be to set DS-4 rates equal to cost of service. (Resp. Ex. 20.0, pp.6-7).

Mr. Higgins claimed further by that DS-3 customers may have an incentive to increase their demand to 1,000 kW to qualify for the lower DS-4 rates. Unfortunately, Mr. Higgins' simple statement fails to acknowledge or consider the rates in their totality.

Customers will be assigned either the DS-3 or DS-4 rate based on the billing period from February 2005 through January 2006. Customers will not be permitted to cross over to DS-4 until June 1, 2008, and this will be based on usage from July 2006 through June 2007. Therefore, the customer that is considering taking service under DS-4 because of the lower rates as Mr. Higgins' supposes, must take into account its billing demands in 2008 and reach a demand level of at least 1,000 kW sometime between the period of July 2006 and June 2007. Whether these customers can increase their demand during that period of time is an unknown and moreover, whether they would benefit is also an unknown. This is so because a customer that would artificially increase its demand in order to take the DS-4 rate will pay the higher Distribution Delivery Charge for the month and higher Transformation Charges for the ensuing year. Further, once a customer is taking service under DS-4, its ability to switch supply options change. Whether or not a DS-3 customer will actually view the lower rates under DS-4

as an incentive, given the uncertainties described above and the potential for higher charges is really nothing more than speculation. (Resp. Ex. 41.0, pp.4-5).

Mr. Higgins' analysis was also shown to be flawed. While his proposal helps DS-3 customers supplied from primary voltage lines, it hurts those DS-3 customers that are supplied from high voltage lines. DS-3 customers taking service from high voltage lines will actually be subject to a greater departure between the DS-3 and DS-4 rates. (Resp. Ex. 41.0, p.6).

c. Wal-Mart Position

Wal-Mart witness Selecky generally discussed the desire to ensure that rates be set at cost. In his direct testimony, he recommended that any reduction from the requested revenue requirement be allocated to those service classifications that are above cost of service. (Wal-Mart Ex. 1.0, pp.23-24). The Ameren Companies rejected Mr. Selecky's position, because different approaches to class revenue responsibility are needed. (Resp. Ex. 20.0, p.19).

d. CUB Position

CUB contends that the residential and governmental classes are less risky to serve than other customer classes and, therefore, should receive a rate increase no more than 90% of the system average. (Corrected CUB Ex. 2.0, pp.15-18). The working premise for the CUB position is completely without merit.

Ameren Companies witness Jones gave several reasons for rejecting the CUB position, to wit:

- The CUB position is an affront to the Commission's past practice of moving rates toward an equal rate of return or equal proportion of cost responsibility when possible.

- Uncollectible exposure and weather related revenue risks are actually higher for the residential class compared to other rate classes, thus making the residential class more risky than the other classes from a revenue standpoint.

- It should be recognized that the Ameren Company recommended cost of service study actually assigns less cost to the residential and small use customer classes; other parties have questioned whether setting rates at something less than cost is justified.

- The Ameren Company revenue allocation method strikes an appropriate balance between implementing cost based delivery service rates and customer bill impacts, which takes into consideration the Commission- approved bill impact adjustment from the auction cases. The Ameren Company proposal is to reduce delivery service rates to the DS-1 class by 8.7% for AmerenIP, 3.6% for AmerenCIPS, and 16.6% for AmerenCILCO.

(Resp. Ex. 20.0, pp.8-9).

In rebuttal, CUB persisted in its arguments that the residential class was less risky to serve but to no avail. Charts relied upon by CUB witness Thomas intending to show the variability in sales as between the residential class and the non-residential class erroneously portrayed the change in sales from one month to the next. When a two month moving average is used, it is clear that the variability in sales is greatly reduced for the commercial and industrial classes as compared to the residential class. In fact, the commercial and industrial sales are more stable than residential sales, the former providing the utilities with a much more stable source of income throughout the year. (Resp. Ex. 41.0, p.8).

The reason for the variability in sales for the commercial and industrial class as represented by Mr. Thomas is distorted. During the period of July 1998 through January 2000, both AmerenCIPS and ComEd were in the process of implementing new

billing systems. This undertaking likely resulted in a month to month variation in the data relied upon by CUB.[13] The problems associated with implementing a new billing system include bills not being issued in a timely fashion or adjusting to the number of days in a billing period. (Resp. Ex. 41.0, p.7-8). Hence, by relying on the faulty data set as did Mr. Thomas, he fails to recognize easily explained commercial and industrial sales variability. Indeed, the corrected data, with appropriate adjustments, show that these classes provide higher predictability and stability of sales to Illinois utilities than does the residential class. As such, CUB's position is unsupported by the record and should be rejected.

e. AG Position

AG witness Rubin had objected to the removal of the 5% rate increase floor applied to the DS-4 class. (AG Ex.2.0, pp.9-10). As discussed elsewhere, it is appropriate to remove this threshold as it would have applied to only AmerenCIPS DS-4 customers in any event, and the increases to AmerenCIPS' customers are relatively modest. (Resp. Ex. 41.0, p.10).

The AG had generally complained about the residential rate impact. Mr. Jones noted the DS-1 rate class was the beneficiary of the DS-1 through DS-3 revenue allocation methodology. Further, the AG has offered no other proposal. (Resp. Ex.41.0, p.11).

2. Minimum Distribution System Study

[13] The CUB charts intending to show the disparity in sales rely upon different scales for the residential, commercial, and industrial classes, pictorially distorting the results of the CUB analysis. (Resp. Ex. 41.0, p.10).

IIEC witness Alan Chalfant and Wal-Mart witness Selecky recommended that distribution plant accounts 364-Poles, 365-Overhead Conductors, 366-Underground Conduit, 367-Underground Conductors, and 368-Line Transformers should be allocated based on a minimum distribution system basis. (IIEC Ex. 2.0, pp.18-22; Wal-Mart Ex. 1.0, pp.15-23). The Ameren Companies believe there is merit to the allocation of these plant accounts in the manner being recommended, however, the Commission has indicated a preference for the NCP method. Conversely, the Commission has shown no interest in the minimum distribution method. (Resp. Ex. 19.0, pp.3-4).

Only if the Commission is convinced that IIEC and Wal-Mart have put forth some persuasive reasoning different than what the Commission has heard in the past, the Ameren Companies should not be ordered to undertake time consuming and costly studies for the benefit of certain parties. Such a study could take one person up to nine months to complete. (Resp. Ex. 19.0, p.4; Tr. at 322).

E. Rider QF

The Ameren Companies proposed Rider QF-Qualifying Facilities, which would pay QF customers a rate based on MISO locational marginal prices (MISO LMP). (See AmerenCILCO Ex. 10.0, p.38). Basing the price to be paid to these customers on locational marginal pricing is appropriate because the amount of energy purchased in the auction to serve Rider RTP-L customers, is equal to the customers' real time requirements less the energy provided by the QF. This amount represents the Ameren Companies' avoided costs under the BGS-LRTP supplier forward contract (because it is the cost not being paid to the supplier), and that cost in a given hour is equal to the MISO locational marginal price for the same hour. (Resp. Ex. 20.0, p.30). Notably, Part 430 of

the Commission's rules requires the payment to the customers be based on the utility's avoided costs. Specifically, 83 Il.Admin.Code Part 430.30 provides as follows:

> "Avoided costs" means the incremental costs to the electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the utility would generate itself or purchase from another source (18 CFR 292)."

Staff witness Rockrohr did not object to the use of locational marginal pricing but recommended the Ameren Companies include a fixed price payment option within Rider QF. Mr. Rockrohr's reasoning was essentially two-fold: a small prospective QF owner may have difficulty predicting an order of magnitude for the value of excess generation and second, some QF owners would find it impossible to conduct a cost analysis unless a fixed cent per kWh option was available. (ICC Staff Ex. 9.0,p.17).

It should be observed Mr. Rockrohr has no basis in fact for his belief or perception as to what QF owners believe or do not believe. He conducted no survey of any kind. He did not meet with one QF customer about this matter. He did not know how many QF customers were located in the Ameren Companies' service territories. He did not know how much load was being served by QF facilities in the Ameren Companies service territories. (Tr. at 795-798). In the end, his contentions about what is best for QF customers, is simply a matter of conjecture and speculation.

Aside from the above infirmities, the notion that a prospective QF customer would perform some extended cost benefit analysis based on an Ameren Company stated tariff rate makes no sense. As pointed out by Mr. Jones, and as required by the Commission's rules, the current QF rates change every year. If, indeed, a prospective QF customer intended to do some meaningful cost benefit analysis, that

customer would examine a variety of data sources and review historical and forward price information provided by the Ameren Companies, as well as MISO data. (Resp. Ex. 20.0, p.31). A fixed price option lends nothing to a proper evaluation of the QF economics, and this was not refuted by Staff.

More importantly, the effect of the Staff proposal will result in a mismatch between cost and revenues arising from paying QF customers fixed cents per kWh value. This is so because the BGS-LRTP purchases, which are used to supply Rider RTP-L customers, are off-set by any QF production. These suppliers will be paid at the MISO LMP prices for energy they provide, and the Ameren Companies will charge Rider RTP-L customers the same MISO LMP prices for energy consumed. This will create a balance in the costs incurred and revenues paid. However, a customer taking the fixed price option under Rider QF will create an imbalance between the cost and revenues in every single hour in which the MISO LMP does not equal the fixed price option. (Resp. Ex.20.0, pp.31-32). Mr. Rockrohr did not disagree that Rider RTP-L customers could pay more for their energy because of QF customers taking the fixed price compensation package (Tr. at 794).

Mr. Jones put forth examples of the disparate impact as a result of customers taking the fixed price option. They demonstrate the mismatch between the Ameren Companies' avoided costs and a fixed QF payment, and in the end the mismatch flows through the Rider RTP-L customers. Rider RTP-L customers will pay either a higher or lower rate than otherwise required. (Resp. Ex. 20.0, pp.33-34).

Aside from Rider RTP-L customers paying something different than the cost to provide them energy, which is an affront to cost causation principles utilized in

ratemaking, the price disparity is likely to have a chilling effect on customers interested in Rider RTP-L. RTP appears to be the bedrock service that will help ratepayers control their energy costs post 2006. Indeed, the Commission has gone on record and opened rulemakings to support RTP. It would be counter productive to come out of the gate with a price for RTP that is wrong. Customers taking real time pricing service have an expectation that they will pay an hourly price for energy based on market conditions and will seek to take advantage of the market. However, under the Staff proposal, the hourly price will not reflect the market. Instead, the RTP-L price under the Staff proposal reflects the fixed price option subsidy.

Staff counters by suggesting over some period of time the fixed price option and the MISO LMP price will be about the same and therefore Rider RTP-L customers would be indifferent. (ICC Staff Ex. 20.0, p.6). Mr. Rockrohr never explains why that would occur and it seems self evident that if it did, it would only be a matter of coincidence. Further, the fixed price option will change from year to year, adding to the real unlikelihood the prices will someday balance out.

The Ameren Companies are aware the Commission has accepted the Staff's proposal in the ComEd delivery service tariff case, that is, to require a fixed price option with respect to ComEd's proposed Rider POG. Nonetheless, the Ameren Companies maintain the record in this proceeding overwhelmingly demonstrates the impropriety of using a fixed price option. The Ameren Companies recommend at the very least that the Commission support the use of the MISO LMP price only for Rider QF and in time, based on experience in the ComEd service territory, examine again whether small prospective QF customers have any desire for a fixed price option.

F. Supply Procurement Adjustment

1. Recovery of supply-related costs

At issue as between CNE/PES in the Ameren Companies is the recovery of supply related costs to the SPA. Both Dr. O'Connor and Mr. Domalgaski basically take the same position, that the Ameren Companies should recover all supply related costs through the SPA. The Ameren Companies do not disagree with this premise.

As explained by Mr. Cooper in both his rebuttal and surrebuttal testimonies, categories of supply related costs include the direct and indirect costs of procuring and administering power and energy supply for all customers, except for those costs recovered from customers and other stated charges. Mr. Cooper testified the costs to be recovered include professional fees, cost of engineering, supervision, insurance, payment for injury and damage awards, taxes, license, and other administrative and general expenses not already included in the auction price for power supply. Other costs to be included are capital and operating costs for generation resources incurred outside the auction process and any costs assigned to the power supply administration function, as approved by the Commission, from time to time. (Resp. Ex. 39.0, pp.6-7). As can be plainly seen, the costs that are intended to be recovered through the SPA are, in fact, supplied related.

2. Amount of supply-related costs

There is no dispute between Staff and the Ameren Companies that the amount of $812,857 for Ameren Company personnel and related costs necessary to obtain the power supply should be recovered through the SPA. Resp.' Exhibit 36.14, Schedule 1, provides the amounts that have been specifically quantified and attributable

for recovery by Staff or intervenors. The SPA adjustment was detailed in Mr. Stafford's supplemental direct testimony. (Ameren Ex. 6.05, p.2).

Staff witness Ebrey in her rebuttal testimony, disagreed with the amount of BGS tariff support costs as they were quantified by the Ameren Companies on Respondent's Exhibit 16.15, claiming they should be recovered through the SPA and not through the delivery service rates as proposed by the Ameren Companies. The overall level of costs to be recovered, however, is provided for in Resp.' Exhibit 36.5 and included on Resp.' Exhibit 36.14, Schedule 1.

Should the Commission ultimately find that the amount of BGS tariff costs supported differs from the amounts proposed by the Ameren Companies, then the amounts shown on Resp.' Exhibit 36.14, Schedule 1 would need to change. Mr. Stafford was of the view that this would satisfy Staff witness Ebrey with regard to the concerns she outlines in her testimony. (ICC Staff Ex. 13, p.26.).

3. SPA tracking trhough the Market Value Adjustment Factor

The Ameren Companies have proposed the recovery of SPA costs via an adjustment mechanism within Rider MV and its associated MVAF mechanism. This is recommended because the Rider MV adjustment mechanisms have the unique ability to precisely recover the SPA costs established by the Commission. In effect, the use of a tracking mechanism similar to the Market Value Adjustment Factor ("MVAF") within Rider MV accounts for a change in the kilowatt hours sold and then adjusts the charge to be recovered with respect to the SPA costs. (AmerenCIPS Ex. 8.05, pp.4-6; Resp. Ex. 18.0, p.3).

Mr. Cooper testified by way of example of the appropriateness of tracking SPA costs through an MVAF type mechanism within Rider MV. Assume the SPA costs were set at a level of $1 million by the Commission, and the number of kilowatt hours sold in a year was 100 million, the resulting charge would be 0.01 cents per kilowatt hour. However, kilowatt hour sales will change due to a variety of factors--weather, customers taking RES supply, economic conditions and so forth. Even though the SPA costs remains at a level of $1 million, the MVAF like mechanism would result in a change or adjustment to the charge to reflect variations in kilo-watt hours sold. There would also be a true-up or reconciliation mechanism to ensure that the Ameren Companies did not recover any more or any less, than the amount authorized by the Commission. (Resp. Ex. 18.0, p.2).

In contrast, Staff witness Ebrey proposes to utilize test year sales level for determining the SPA rate. Therefore, if the Ameren Companies are required to use fixed kilowatt-hour sales, there will be a mismatch between the approved SPA costs and billed SPA charges. This is so because the utilities will not experience kilowatt hour sales greater than the test year. Assume the test year is 100 units. Assume there is customer switching greater than what has occurred historically. This is a fair assumption because we are moving from low cost rates to market priced rates. Now, there are only 90 units consumed. The 90 units cannot produce the same level of revenue as 100 units. Hence, the Ameren Companies, all things being equal, suffer a revenue shortfall. (Resp. Ex. 18.0, p.4).

As indicated above, the basic difference between Ms. Ebrey and the Ameren Companies is whether the MVAF mechanism should be employed as a

complement to Rider MV for the recovery of SPA costs. Clearly, the MVAF mechanism contains a tracking feature that ensures precise recovery of SPA costs, regardless of the level of SPA costs or the level of future power and energy sales under the Ameren Companies' Rider MV. Said preciseness is obviously in the better interests of and represents fairness to all stakeholders and, therefore, the Ameren Companies proposal should be adopted by the Commission.

G. Line Extension Refunds

Section 410.410 governs the Commission's rules regarding line extension provisions. Generally, Section 410.410 outlines a prescriptive protocol by which the utility can extend a customer's distribution system, the amount of free extensions, deposits, and the like. Section 410.410(a)(2) provides that the line extension provisions as outlined in subsections (b) and (c) are not binding in the event the utility demonstrates that its line extension provisions are more favorable to applicants. In this respect the Ameren Companies put forth a proposal that is far more favorable than what is otherwise provided under subsections (b) and (c). Therefore, the Ameren Companies should be excused from the 10 year refund tracking obligation in return for the five year refund tracking obligation and accompanying options.

Mr. Jon Carls on behalf of the Ameren Companies identified the following benefits to residential customers:

- The option to reduce the upfront charge which assumes there will be one new customer extended from the extension, in return for making the payment become a non-refundable contribution.

- The change from existing practices to make the demarcation point between the line/service extension be the customer's property line, which will result in more extensions meeting the definition of "service" instead of "line", and consequently the amount of the payment will often be lower.
- An option for the customer to install conduit for service extensions and possibly for some line extensions, which could reduce the amount, if any, of the required payment.

(Resp. Ex. 31.0, pp. 10-11).

Staff took issue with the legitimacy of these benefits as it related to residential customers (though acknowledging that for other customers the proposal is more favorable); however, all of Mr. Rockrohr's claims were soundly refuted. Based on the Ameren Companies actual use of the concept identified in the first bullet point, applicants generally know whether someone else will be utilizing that extension in the near future and have often agreed to pay a lesser amount upfront and forego the tracking/refunding possibility. With regard to the second bullet point, the change of demarcation point, historically the cost for service extensions are almost always lower than for line extensions and, therefore, customers will see a benefit to change of the demarcation point. As for the last bullet point, the customer's option to install conduit, Mr. Carls explains the cost to the customer will be at a reduced charge, perhaps even free, depending on the actual footage. (Resp. Ex. 51.0, pp.2-3).

The Ameren Companies maintain that in return for the above options, reducing the tracking of the refund from 10 years to five years is a clear win-win for customers. Implicitly realizing the merits of the proposal, Staff witness Rockrohr

suggested that the Ameren Companies offer both, that is, offer the package of options but also be required to continue to track refunds over a 10 year period of time.

The Ameren Companies would have to seriously consider whether providing the options as well as the burden of tracking refunds over both a five and 10 year periods of time, is appropriate, that is, should the Commission side with the Staff on this position, the Ameren Companies will have to reconsider making the options available. (Resp. Ex. 51.0, p.3).

H. Residential RTP Program

CUB, in its direct case, recommended a real time pricing ("RTP") program. (See Corrected CUB Ex. 2.0, pp.21-36). The Ameren Companies initially took issue with the CUB proposed RTP program as there was a lack of detail and other issues that had yet to be resolved. (Resp. Ex. 20.0, pp.20-22). In rebuttal, CUB witness Thomas provided more detail, such that the Ameren Companies do not object to the CUB proposed RTP program subject to certain adjustments as reflected in Mr. Jones' surrebuttal testimony. (See CUB Ex. 4.0, pp.34-40).

The adjustments are discussed at page 27 of Mr. Jones' surrebuttal testimony and would result in an incremental meter lease cost of $6.94, as well as an increase to program costs by an additional $193,074.00, which results in a per residential customer per month value of 11.8 cents. (Resp. Ex. 41.0, p.27). The other adjustment comes from using a four year average instead of three, increasing the true cost of implementation from $1,067,488 (CUB Ex. 4.07) to $1,291,457 (Resp. Ex. 41.0, p.27). The total cost of implementing the RTP program is $1,484,531.

In support of the CUB proposed RTP program, the Ameren Companies developed a new tariff, Rider ESP-Energy Smart Program, identified as Schedule 41.3 to Mr. Jones' surrebuttal testimony. The tariff governs the rules surrounding the residential RTP program. Notably, customers enter into a participation agreement with the program administrator. Space in the program may be limited based on target levels over a four year period of time. Rider ESP also details the conditions that apply to customers taking service under the rate. (See Resp. Ex. 41.0, pp.29-30, Resp. Ex. 41.0, Schedule 41.3).

Finally, implementation of Rider ESP would require changes to the proposed Miscellaneous Fees and Charges provisions in the delivery service tariff. Specifically, additional wording was recommended that would allow a waiver to the Incremental Metering Charges for Rider RTP for residential customers up to the number of program participants as identified by CUB. (Resp. Ex. 41.0, p.31).

I. Uniform Lighting Rates for AmerenIP

In its direct case the Ameren Companies explained their approach to developing the various types of lighting services as well as the cost of service. Mr. Jones explained in great detail the proposed standard lighting offerings including Area, Directional and Decorative. He further explained that existing lighting service is separated between "street lighting service" and "protective lighting service". (See generally AmerenIP Ex. 10.0, pp.24-25).

In terms of the cost of service, Mr. Jones testified the cost associated with providing street/protective and residential/non-residential services are virtually the same. In fact, "street protective" lighting service has been priced the same for AmerenCIPS and AmerenCILCO. However, for AmerenIP, the level of the increase to the residential

Protective Lighting Service would be several times the average increase and, therefore, AmerenIP initially proposed to mitigate the increase to residential Protective Lighting customers. AmerenIP then proposed to increase prices to Street Lighting to produce a relatively modest increase, and use the additional revenue contribution to reduce prices for Protective Lighting. AmerenIP's proposed prices would produce increases of about 15% for the Street Lighting group, and 32% and 43% for the non-residential and residential Protective Lighting groups, respectively. (AmerenIP Ex. 10.0, pp.25-26).

Cities witness Richard Cuthbert recommended that lighting rates be set at cost of service, that is, there would be no interclass subsidies. In the alternative, Mr. Cuthbert recommended that all of AmerenIP's other rate classes would share in the subsidy.

In light of the Cities' rebuttal position and the lack of any objection to the Cities' recommendations, AmerenIP re-evaluated the DS-5 revenue allocation and rate design proposal for AmerenIP. Mr. Jones testified there was some merit to the Cities' position insofar as Protective Lighting is an elective service whereas Street Lighting tends to be an expected public service. While the financial impact to a municipality could be large, the financial impact to residential customers would be relatively modest. Therefore, the Ameren Companies have no objection to uniform pricing for comparable Street Lighting and Protective Lighting services.

The Ameren Companies do oppose Mr. Cuthbert's alternative, where the subsidy would come from other rate classes, because all other customer classes are proposed to receive delivery service increases greater than 15%. The point being,

exacerbation of the rate increases should be minimized. If any subsidy is warranted, it should come from the Street Lighting group. (Resp. Ex. 41.0, pp11-12).

Finally, Mr. Jones corrected a number of values relied upon by Mr. Cuthbert. The proposed and corrected values are displayed in the table at page 16. (Resp. Ex. 41.0, p.17). There does not appear to be any dispute as to the correctness of these values.

IV. MISCELLANEOUS SERVICES ISSUES

Each of the Ameren Companies submitted proposed tariffs for metering services and line extensions. (*See* Central Illinois Light Company d/b/a AmerenCILCO, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022; Central Illinois Public Service Company d/b/a AmerenCIPS, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022;; Illinois Power Company d/b/a AmerenIP, Proposed Ill. C. C. No. 35, Original Sheet No. 4.009-4.015; 4.021-4.022.) The International Brotherhood of Electrical Workers, AFL-CIO Locals 51, 309, 649, 702 and 1306 ("IBEW" or "Unions") intervened in this proceeding under the guise of a "just and reasonable" rate investigation , to object to these tariffs on the basis that the tariffs, if approved, would result in job losses for IBEW members.[14] For example, IBEW argues the utility should not allowed to use a contractor that has employees with a different skill set than "utility employees that are replacing or personnel working for an ARES or meter service provider." and that such practice is not "just and reasonable". (IBEW Ex. 1.0, 9.19.) Nonetheless, the record evidence, however, fails to establish any meaningful nexus between, on the one hand, the tariffs; and on the other, the practices that the IBEW claims will result in job

[14] Although five local unions intervened in this proceeding, the IBEW submitted testimony only from Locals 51 and 702.

losses. The Ameren Companies' metering services tariffs, for example, are irrelevant to whether outside service providers hired to expand the Ameren Companies' Automated Meter Reading ("AMR") system in Illinois are subject to Commission certification as "meter service providers" under 83 Administrative Code Part 460, as the IBEW claims they are. Likewise, the Ameren Companies' line extension tariffs, which would permit customers to install their own conduit and also authorize pilot programs to explore allowing subdivision developers to install some distribution facilities, has already been the subject of both a labor grievance and a prior Commission proceeding. The Commission found that labor matters have nothing to do with the Public Utilities Act ("Act") and therefore are not the appropriate subject of Commission proceedings. *Investigation Into the Proper Allocation of Line Extension and Service of Installation Costs*, Docket No. 03-0767, Order of Rehearing of April 6, 2006, at 3.

The IBEW is simply trying to re-litigate its labor disputes in the context of a distribution rate case. Indeed, each of its witnesses reserved to themselves the right to "…to discuss the results of the arbitrator's decision in the IBEW's rebuttal testimony." (IBEW Ex. 1.0, p.31) But the IBEW has failed to establish that any aspect of the Ameren Companies' metering services or line extension tariffs is unjust or unreasonable under the Act. The Commission should approve these tariffs.

Finally, as a matter of law, the IBEW's tortured reading or misreading of Part 460—the center of its case-falls flat and should be thoroughly rejected by the Commission.

A. Line and Service Extensions

IBEW complains about two aspects of the Ameren Companies proposed line extension tariffs. First, they complain that residential customers and subdivision developers should not be permitted to install their own electric conduit. Second, they argue that subdivision

developers should not be permitted to install their own distribution facilities. The Unions have failed to show that either policy is unjust or unreasonable.

The evidence in this proceeding shows that the most common method for new service installations is to direct-bury the conductor. (Tr. at 660, 699-700.) The Ameren Companies' proposed tariffs would allow customers and subdivision developers, at their option, to have the conductor installed in a plastic conduit. (Tr. at 657.) A conduit provides greater protection against accidental line strikes than bare conductor. (Tr. at 639.) For customers that choose to install conduit, the customer is permitted to dig the trench and also to lay the conduit in the ground. (Tr. at 661.) Ameren Company employees will then install the conductor in the conduit and make the necessary service connections. (Tr. at 661-662.) All customer-installed conduit must be installed in a manner consistent with good engineering practices and is subject to inspection by the Company before any service connections are made. (Resp. Ex. 51, p. 4) The tariffs also seek authority to "develop alternative options for developers regarding installation of electric infrastructure in Subdivisions, which may include but are not limited to: developer installation of some distribution facilities . . . ." (*E.g.*, AmerenIP Ill. C. C. No. 35, Original Sheet No. 4.015(iv).) The Ameren Companies developed the line extension tariffs because of concerns expressed by customers over the cost and timeliness of new installations. (Tr. at 658.)

The IBEW argues that allowing customers to install conduit, or allowing developers to install their own distribution facilities, constitutes "unbundling" under Section 16-102 of the Act because the Ameren Companies are proposing to allow customers and contractors to perform work previously performed exclusively by them. (IBEW Ex. 2.0 , p. 40.) They further argue that where a utility proposes to offer an "unbundled" service, the Commission, in

determining whether tariffs providing for such services are just and reasonable, is required to consider the effect of unbundling on utility company employees, as stated in Section 16-108(a). (*Id.*) Because the Ameren Companies' line extension tariffs supposedly will result in a loss of jobs for IBEW members, the IBEW urges the Commission to reject the tariffs as unjust and unreasonable.

IBEW cites no authority for its claim that allowing customers to install conduit constitutes "unbundling." In January 1999, in Docket No. 99-0013, the Commission entered an order initiating a proceeding under Section 16-108(a) of the Act to investigate and make determinations about unbundling of metering and billing services. At no time during the subsequent 21 months of investigations and workshops, in any of three interim orders in that case, or in the 88 page final order is there a single mention of anything to the effect that allowing a customer to install conduit on its own property constitutes "unbundling." (Resp. Ex. 31, p. 5.) IBEW's witnesses admit that their conclusion that allowing customers to perform this work is their lawyer's opinion, not their own. (Tr. at 653.)

Sections 16-102 and 16-108 do not support a conclusion that allowing customers to install their own conduit constitutes "unbundling." Section 16-102 defines "unbundled service" as "a component or constituent part of a tariffed service which the electric utility subsequently offers separately to its customers." But whether the Commission is required to consider the effect of "unbundling" on utility employees depends on exactly what kind of service is being unbundled. Section 16-108, titled "Recovery of costs associated with delivery services," grants authority to the Commission "to review, approve and modify the prices, terms and conditions of those components of *delivery services* not subject to the jurisdiction of the Federal Energy Regulatory Commission, including the authority to determine the extent to which such

delivery services should be offered on an unbundled basis." 220 ILCS 5/16-108(a) (emphasis added). Thus, if a statutorily-defined "delivery service" is being unbundled, Section 16-108(a) comes into play and the Commission must consider the effect on utility employees of unbundling that service.

The Act makes it clear that not every service provided by an electric utility constitutes a "delivery service." Under the Act, "delivery service" means "those services provided by the electric utility that are *necessary* in order for the transmission and distribution systems to function so that retail customers located in the electric utility's service area can receive electric power and energy from suppliers other than the electric utility, and shall include, without limitation, standard metering and billing services." 220 ILCS 5/16-102 (emphasis added.) By no stretch of the imagination can conduit installation be considered a service component "*necessary* in order of the transmission and distribution systems to function so that retail customers . . . can receive electric power and energy from suppliers other than the electric utility . . . ." The use of conduit in service line extensions is the exception rather than the rule; most of the time the conductor is direct buried. (Tr. at 660.) The testimony at hearing revealed that because of cost considerations, the Ameren Companies expects very few customers to elect to install conduit. (Tr. at 701-702.) Because conduit is not necessary for the distribution of electricity to customers, the installation of conduit is not a "delivery service," and because it is not a "delivery service," the Commission does not need to consider the effects to utility employees of "unbundling" this service.

Allowing subdivision developers to install their own distribution systems also cannot be considered "unbundling" under Section 16-102. Under the proposed tariffs, the Ameren Companies are not proposing to "unbundle" the installation of distribution facilities in

the sense that any customer will be permitted to install its own distribution facilities. The tariffs merely propose to give the Ameren Companies the authority to develop pilot programs to determine the feasibility of allowing a limited class of customers; *i.e.*, subdivision developers; to hire their own contractors to install distribution facilities. (*See* Resp. Ex. 51.0, p.8.) Upon installation, these facilities would then be sold to the Ameren Companies. (Tr. at 663.) The Ameren Companies' IBEW employees would continue to service these facilities, just as they do today. (Tr. at 664.)

The IBEW's direct testimony could not be clearer about what their chief complaint with the tariffs really is: "What we're talking about here is a dramatic loss in man hours that would otherwise be performed by IBEW members." (IBEW Ex. 2.0 , p. 37.) Whether this is true is irrelevant. The IBEW's concern about job losses clearly implicates a labor relations issue that is beyond the scope of this or any other Commission proceeding. *Investigation Into the Proper Allocation of Line Extension and Service of Installation Costs*, Docket No. 03-0767, Order of Rehearing of April 6, 2006, at 3. Moreover, as explained above, the line extension policies do not implicate "unbundling" of any "delivery service." Accordingly, there is no basis for the Unions' claim that Section 16-108(a) requires the Commission to consider the effects of the proposed tariffs on the Companies' employees.

IBEW also attempts to make the case – unsuccessfully – that the line extension tariffs are unreasonable because they will permit customers to perform dangerous activities. IBEW witness Miller, for example, testified about a number of alleged hazards associated with customers installing their own conduit. One of these hazards is digging into existing utilities. (Tr. at 637.) But as Mr. Miller acknowledges, this hazard exists regardless of whether it a customer or an Ameren Company employee performing the trenching. (Tr. at 637.) This hazard

can be reduced by customers' calling J.U.L.I.E. before performing trenching, as they are required to do by law. (Tr. at 638; 220 ILCS 50/.) Mr. Miller also testified about the hazard of flying debris caused by trenching equipment, but conceded that this hazard also exists regardless of who does this work. (Tr. at 639.) Further, in his direct testimony, Mr. Miller discusses the potentially "fatal" risk of trench cave-in. After admitting at hearing that most conduit trenches are only 18 to 24 inches deep, the witness was forced to concede that this "risk" is vastly overstated. (Tr. at 640-641.) Tellingly, while Mr. Miller testified in his direct testimony of at least 23 known instances (which predate this proceeding) where customers have installed their own conduit (Tr. at 641-642), he admitted on cross examination that he is not aware of any instance where the "hazards" discussed in his direct testimony actually happened. (Tr. at 643.) The IBEW's speculation about what could happen if customers install their own conduit is simply contrary to fact.

The IBEW essentially is asking this Commission to find that any tariff provision that results in a reduced workforce is *prima facie* unjust and unreasonable. Nothing in the Act supports this conclusion

The IBEW has failed to provide any basis to reject the Ameren Companies' proposed tariffs. None of IBEW witnesses testified that any proposed rate or charge for metering or line extension services is unjust or unreasonable, or that any aspect of the metering or line extension tariffs is in any way relevant to whether any costs that the Ameren Companies seek to recover in rates were prudently incurred. The IBEW's entire case is predicated on a theory that any utility policy that results in workforce reductions is necessarily unjust and unreasonable, regardless of whether the policy benefits the utility, its investor, ratepayers and the public. Their theory is fatally flawed; nothing in the Public Utilities Act authorize the Commission to reject

tariffs that could lead to workforce reductions. The IBEW's claims should be rejected and the Commission should approve the Companies metering services and line extension tariffs.

B. Metering Services

The Ameren Companies' proposed metering services tariffs state that the Ameren Companies will "own, furnish, install, calibrate, test, and maintain all Company meters and all associated equipment used for retail billing and settlement purposes in its service area," unless the customer hires a Meter Service Provider ("MSP") to perform these services. (*See*, *e.g.*, AmerenIP proposed Ill. C. C. No. 18, Original Sheet No. 4.021.)

The IBEW does not specifically object to the metering services tariffs *per se*. Rather, IBEW's complaint centers on the Ameren Companies' planned expansion of their AMR system. An AMR system consists of a module within individual electric meters that transmits data via a wireless communications system. (Tr. at 712-713.) The electric meter, which is owned by the Ameren Companies, remains the fundamental measure device for electricity consumption. (Tr. at 714-715.) Cellnet Technologies, Inc. ("Cellnet") owns the module inside the meter that transmits data, as well as the wireless communications system that transmits the meter data to the Ameren Companies. (Tr. at 719-720.) The benefits of an AMR system include the elimination of estimated bills, less intrusion onto customer property, better outage response, better information for customer service representatives in assisting customers, and special meter readings on the day requested. (Tr. at 626.) An AMR system virtually eliminates the need for manual meter reads. (Tr. at 713-714.) No IBEW witness challenged or took issue with these customer benefits. (Tr. at 636.)

The Ameren Companies have used AMR in parts of Missouri and Illinois since the 1998-99 time period. (Tr. at 631-632; Resp. Ex. 30, pp.8-9) In October 2005, the Ameren Companies informed the IBEW of plans to expand the AMR system further into the Illinois service territories. (Tr. at 634.) The expansion will require them to replace existing meters with meters containing an AMR module. (Tr. at 719.) The meter exchange will be performed by Terasen Utility Services ("Terasen') as a subcontractor to Cellnet (Tr. at 723-724, 732.) The AMR modules and communications system will be owned and operated by Cellnet. (Tr. at 725.) The agreement between the Ameren Companies and Cellnet requires Cellnet to comply with Part 410, where applicable. (Tr. at 653-654.) The Staff had, in fact, recommended a reference to Part 410 be included as a part of the agreement with Cellnet. (Resp. Ex. 30., p.7.) Notably, IBEW Local 51 has filed a labor grievance over the Ameren Companies' use of Cellnet and Terasen for the AMR expansion. (Tr. at 634.)

IBEW argues that the activities of Cellnet and Terasen in conjunction with the AMR expansion constitute "metering services" as defined in Part 460 and therefore require these entities to become certified under that rule. (Tr. at 651.) But for the Commission to accept this argument, it would have to write Part 410 off the books. Electric utilities such as the Ameren Companies are exempt from Part 460 when they provide metering services within their own service territory. 83 Ill. Admin. Code Section 460.20. Instead, Part 410 applies. 83 Ill. Admin. Code Section 410.100. Although the Unions claim that Part 460 applies to utilities when they use outside contractors (*e.g.*, IBEW Ex. 2.0, p. 18), nothing in Part 460 says that. (Tr. at 653.) Likewise, nothing in Part 410 says that a utility has to use its own employees to perform metering services under that Part.

The Commission need not wait to for the IBEW brief to see its legal argument. Here is the IBEW legal position a set forth in its witnesses' testimonies:

"…., based on the advice of counsel, Code Part 460 applies to Cellnet and Terasen if they provide metering service on behalf of AmerenCILCO. As I understand it, Cellnet and Terasen are unregulated entities and not public utilities. When a public utility provides metering service *with its own employees* in its service territory, Code Part does not apply to the utility. When the utility uses an outside contractor or contractors to provide metering service, however, Code part 460 applies to utility contractors providing metering service." (IBEW Ex. 1.0, p.17.)

What a misleading statement. Section 460.20 states in part "…nor shall it apply to any electric utility's *operation* within the utility's service territory." It goes on to state that it applies to "..an electric utility's *operations* when it is providing metering services outside of its service territory." (emphasis added). Nowhere does the word "employee" appear in this section. It is absolutely disingenuous for the IBEW to have misled the ALJs and Commission, and even to go so far as to *italicize* the " with its own employees" phrase. Rather, it clear on the face of the rule that the utility can do what the Ameren Companies are doing—performing its "operations" within "its service territory".

Continuing, Cellnet and Terasen are *not* subject to certification under Part 460 because they will be performing work on behalf of Ameren, and not on their own behalf as Meter Service Providers ("MSPs") (Tr. at 748-749.) The work they will perform will be limited to exchanging single-phase meters and maintaining the wireless communications system. (Tr. at 723-725.) Neither contractor will have any direct relationship with customers. Instead, each Ameren Company will "own, furnish, install, calibrate, test, and maintain all company meters

and all associated equipment used for retail billing and settlement purposes in its service area." (*E.g.*, AmerenIP Proposed Ill. C. C. No. 18, Original Sheet No. 4.021.) Ameren will be providing "metering services" under its tariff, not Cellnet or Terasen. (Tr. at 732.)

IBEW witnesses parse through the specific work activities that Cellnet and Terasen will perform to attempt to show that these activities fall within some of the 16 different activities that Part 460.15 defines as "metering services." (*E.g.*, IBEW Ex. 2.0, pp. 12-13.) But nothing in Part 460 suggests that any entity that performs any one of these 16 functions under contract with a utility is a "meter services provider" subject to certification under Part 460. Utilities have hired outside contractors for many years to perform many different kinds of work. IBEW witness Moore, for example, used to work for L.E. Meyers, a company that "did construction and maintenance for utilities." (Tr. at 649.) When an outside service provider such as L.E. Meyers does work under contract with a utility (such as, for example, substation maintenance), nobody would suggest that the outside service provider is engaged in the provision of electric service and therefore subject to Commission regulation as a "public utility." Doing work for a utility and being a utility are two different things. The same can be said for metering services. Providing a limited number of components of metering service under contract with a utility does not make the entity providing those services a "meter services provider." Performing limited subcontractor work at the direction of the utility and providing a competitive metering service are completely different activities.

The Unions' claim that the tariffs will allow unregulated, unqualified personnel to perform metering services, but they have never produced evidence to back that claim. The only work associated with the AMR expansion that even involves actual meters is the meter exchange service to be provided by Terasen. IBEW does not dispute that Terasen's employees will receive

an amount of training comparable to what AmerenIP's meter changers receive. (Tr. at 656.) The Terasen employees are also represented by IBEW Local 702. (Tr. at 655.) The Unions offer *no evidence* that Terasen employees are, or will, be unqualified. Indeed, they admit that they have no personal knowledge of the level of training, skills or experience of Cellnet or Terasen employees. (Tr. at 654-655.)

Under the proposed tariffs, the Ameren Companies will continue to own electrical meters, just as they always have. The Ameren Companies will continue to inspect and replace meters as necessary, just as they always have. (Tr. at 736, 738.) And, the Ameren Companies will remain subject to the metering service requirements of Part 410. If the Unions come to believe as some future time that an Ameren Company or its contractors have violated Part 410, they are free to file a complaint with the Commission. But the Unions' speculative claims provide no basis for rejecting the Ameren Companies' metering services tariffs.

C. Vegetation Management/Tree Trimming

Staff witness James Spencer recommends that the Commission adopt a new interpretation of Rule 218 of the National Electrical Safety Code ("NESC"), which the Commission has made a part of Illinois Administrative Code 305.20 through incorporation by reference of Section 21 of the NESC. NESC Rule 218(A)(1) states that "[t]rees that may interfere with ungrounded supply conductors should be trimmed or removed." Mr. Spencer testifies that Staff began interpreting Rule 218 as a no-contact rule in October 2002. (ICC Staff Exhibit 21.0, p. 10, line 215.) Notably, if correct, this date does not coincide with the Commission's adoption of any new rule or amendment. Thus, Staff's attempted new interpretation of NESC Rule 218 constitutes illegal rulemaking.

Further, Staff's proposed new rule should not be adopted, because it is an inappropriate interpretation of NESC Rule 218, as shown in the Ameren Companies' testimony. Implementation of such a rule is unnecessary, unwise, unsupported by industry practice, and is contrary to law, as fully set forth in Section V.C.

1. The Ameren Companies' Vegetation and Tree Trimming Practices are Reasonable, Effective and in Compliance with the Law.

Ameren Companies' witness Allen L. Clapp, President of Clapp Research Associates, P.C., Consulting Engineers and President of Clapp Research, Inc., testified that Staff's interpretation of NESC Rule 218 is incorrect. (Resp. Ex. 26.0.) Mr. Clapp is a Member (Chair 1984-1993) of the National Electrical Safety Code (NESC) Committee and the editor of the NESC Handbook, and represented the National Association of Regulatory Utilities Commissioners on the NESC Committee until he became the Chair in 1984, at which time he became an Individual Member of the Committee. Mr. Clapp is a member of the following NESC Subcommittees:

- National Electrical Safety Code Executive Subcommittee 1976-1993 (Chair 1984-93)
- Interpretations Committee 1976-present (Chair 1981-1990)
- Coordination Subcommittee 1978-present (Secretary 1981-84, Chair 1993-present)
- Clearances Subcommittee 1971-present (Acting Secretary over 20 times)
- Strengths and Loadings Subcommittee 1971-present (Secretary 1978-present)

(*Id.* at 2-3.)

Mr. Clapp has served over 35 years on these committees, and is familiar with the NESC, its rules and the changes that have occurred in the NESC over time. As Editor of the NESC Handbook, Mr. Clapp has reviewed every document known to exist relating to the original codification and subsequent revisions of the NESC. Mr. Clapp has been involved in many seminars, discussions, meetings and the like with stakeholders in the industry, who have helped to form consensus around the NESC. (*Id.*)

Mr. Clapp has served on the NESC Subcommittee responsible for Rule 218: NESC Subcommittee 4 on overhead clearances, and has personally examined every document known to exist in the history of this rule. The rule was originally codified as Rule 281 in the 4th Edition (1927) and remained unchanged in the 5th Edition (1941) and 6th Edition (1961). It moved to Rule 218 in the 1990 Edition. Mr. Clapp has personally participated in each of the three modifications to the rule (1977 Ed., 1984 Ed., and 2007 Ed.) – that is, he discussed, considered and debated with his colleagues as to the propriety to each rule change and the associated intent. (*Id.*)

Mr. Clapp testified that each NESC rule recognizes the purpose of the NESC, as stated in Rule 010:

> The purpose of these rules is the practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment. These rules contain the basic provisions that are considered necessary for the safety of employees and the public under the specified conditions.... (*Id.* at 4.)

Mr. Clapp testified that each edition of the NESC has recognized that it may not be practical to prevent contact between portions of trees and utility lines in all cases, due to the competing desires of consumers to (a) have an aesthetic environment (i.e., to limit the drastic pruning or complete removal of trees necessary to absolutely prevent all contact by trees with utility lines and to (b) have economical utility service, but that it is practical to limit such contact between trees and utility lines to levels that are not likely to cause a safety or reliability problem. (*Id.* at 4-5.)

Mr. Clapp testified that there has never been any intention by the NESC to prevent all contact of trees with utility line conductors. On the contrary, the intent of the code has been to require a practical vegetation management program that will limit the opportunity for damage to utility facilities due to contact by vegetation.

Mr. Clapp also testified that the NESC would be updated on August 1, 2006, to clarify the NESC position on its proper intent. Mr. Clapp disagrees with Mr. Spencer's belief that the NESC language intends that utilities must trim trees back far enough that there is no possibility that any limb will grow out and contact an energized conductor before the next pruning cycle. That is not practical to accomplish under any reasonable vegetation management program. (*Id.* at p. 6.)

Experience with tree growth in various areas of the country has shown that, while it is practical to prune far enough back using the so-called natural pruning method to limit the opportunity for future growth to grow back into the line before the next cycle, it is not possible to absolutely prevent any contact at all between cycles without (a) employing such drastic pruning

or complete removal of trees that the adjacent landowners will be ill-served and the health and life of the vegetation will all too often be adversely affected, and (b) spending so much money on needless pruning of trees that would not have grown back into the line that economy of service is adversely affected without significantly increasing system reliability. Indeed, in many municipalities, utilities are not allowed to prune vegetation back far enough to accomplish that goal. (*Id.* at 6-7.)

At the Ameren Companies' request, Mr. Clapp was engaged to study the vegetation management practices in and around power lines. In so doing, Mr. Clapp explained the intended application of NESC Rule 218 as it related to vegetation management around overhead lines. A copy of that report, dated November 29, 2005 and titled National Electrical Safety Code Requirements and Practical Considerations Relative to Vegetation Management Around Overhead Power Lines, has been entered into evidence as Respondents' Exhibit 26.2. The report includes more detail than the above brief discussions. (*Id.* at 7.)

Mr. Clapp's report on the vegetation management practices of the Ameren Companies is attached as Respondents' Exhibit 26.3. In that report, Mr. Clapp concluded that the Ameren vegetation management program of combining (a) a 4-year normal pruning cycle with (b) identifying and scheduling any faster growing trees or trees with pruning limitations such that they might become cycle busters for interim inspection or pruning is a reasonable, practical and pragmatic method of achieving the goal of providing safe and reliable electric service in an economical manner. (*Id.* at 8.)

Notably, Mr. Spencer did not refute any of Mr. Clapp's testimony regarding the correct interpretation of NESC Rule 216 on rebuttal.

In his surrebuttal testimony, Mr. Clapp concludes that Mr. Spencer is uninformed as to the widely accepted industry understanding of the behavior and consequences of vegetation growth in the proximity of conductors. The four-year cycle presently employed by the Ameren Companies, including the targeted treatment of cycle-busters, is expected to limit the opportunity for new growth to contact an energized conductor. In the event that a few trees sprout unexpected sucker growth between cycles, the growth will be small enough that conductor integrity should not be affected. The Ameren Company vegetation management program is reasonably designed and implemented to assure that limbs will be pruned before they reach a size capable of damaging nearby conductors should contact occur. (Resp. Ex. 47.0, pp. 3-4.)

2. The Ameren Companies' Electric Service is Reliable.

The rebuttal and surrebuttal testimony of Ameren Companies' witness Craig Boland demonstrates that Staff's criticisms of the Ameren Companies' service reliability are skewed, because Staff does not normalize for weather-related outages in assessing reliability. (Resp. Ex. 47.0, pp. 1-2.) Mr. Spencer incorrectly claimed in rebuttal testimony that taking weather-related incidents into account The Commission's rules require that Staff take weather and other uncontrollable events into account when assessing a system's reliability:

> The Commission recognizes that circumstances and events beyond a jurisdictional entity's control can affect reliability statistics and the interruptions experienced by customers. The Commission shall

> consider such circumstances and events when evaluating a jurisdictional entity's reliability performance.

83 Ill. Admin. Code Section 411.140(a)(1). Section 411.140(b)(1) further states:

> When assessing a jurisdictional entity's annual report, the Commission shall consider . . . .
>
> G) The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.

And Section 411.140(b)(3) states:

> When assessing a jurisdictional entity's reliability performance, the Commission shall consider . . . .
>
> M) The reliability effects of severe weather events and other events and circumstances that may be beyond the jurisdictional entity's control.

83 Ill. Admin. Code Section 411.140(b)(1).

Despite these clear directives, Staff refuses to take weather into account in assessing the Ameren Companies' system reliability.

D. Other

1. Ameren Companies and CNE/PES MOU

In its direct and rebuttal testimonies Constellation New Energy, Inc and Peoples Energy Services Corporation (CNE/PES) raised several issues or concerns with various business practices by the Ameren Companies. In turn, the Ameren Companies explained or justified certain of these concerns and made other commitments. After a continuing dialogue, the Ameren Companies and CNE/PES entered into a Memorandum of Understanding ("MOU") which was made part of the record as Ameren Companies/CNE/PES Joint Exhibit 1. In the MOU a number of agreements were reached that related to a number of business practices, to wit:

a. Ameren will implement an electronic bulletin board or provide on its website a link where answers to commonly asked questions from retail electric suppliers (**"**RESs**"**) will be posted.

b. Ameren has assigned RESs specific account representatives in the Transmission Services Business Center (**"**TSBC**"**) that will handle billing related matters that go beyond merely answering transmission billing questions as well as to facilitate the process of answering other RES related questions.

c. Ameren will implement the Electronic Data Interchange (**"**EDI**"**) 814-C transaction regarding meter numbers and will work with RESs to ensure that the improved processes are working as designed prior to the implementation date.

d. Ameren will provide 24 months of historical usage information, when available, free of charge to authorized RESs and customers starting January 1, 2007.

e. Ameren will apply the Ameren Data Universal Numbering System (**"**DUNS**"**) number and the DUNS numbers of the individual utilities in a uniform manner across the entire EDI transaction set for each Ameren operating company by no later than September 15, 2006.

f. Ameren agrees to work in good faith with RESs regarding all relevant customer communication plans that may bear upon RES business practices and procedures.

g. Ameren will support the utilization of a "factor" approach to segregate the uncollectibles expenses associated with customers taking bundled service from Ameren and the uncollectibles expenses associated with customers taking only delivery services from Ameren.

h. Ameren agrees to eliminate the Direct Access Service Request ("DASR") Fee and the Standard Switching Fee that appear in the "Miscellaneous Fees and Charges" section of Ameren's proposed tariff.

i. Ameren will support the allocation of the Supply Procurement Adjustment ("SPA") costs to each of the Ameren utilities based on the relative kilowatt-hour sales (i.e. delivered) of each of the Ameren utilities.

j. It remains Ameren's practice to provide all customer account drop information (including retroactive drops) to RESs electronically via an EDI 814-D request.

k. By no later than August 4, 2006, Ameren will post documents/charts to Ameren's website, depicting the customer switching alternatives and enrollment windows for the post-transition period. These documents or charts will be accessible to both RESs and customers under the RES and Customer Portals.

l. Ameren will allow customers to request that Ameren create separate account numbers for their natural gas and electric service upon request. At this time, Ameren does not have a policy objection to allowing Agents, with proper authorization, to make such a request on behalf of a customer. However, the Parties agree to actively and in good faith participate in a workshop process to develop the means and procedures by which Agents can make such requests.

m. As soon as practical, and with a good faith effort to complete this task by no later than September 1, 2006, Ameren agrees to provide the following information on both the Customer and RES Portals on the Ameren Website, to the degree the information is readily available:

- Current Supply Group and Type

- Future Supply Group and Type
- DASR Eligibility Date
- Current rate and supply-type information
- Delivery Services Class
- Ameren Operating Utility

n. Ameren agrees to use a good faith effort, along with CNE/PES, to initiate and participate in a workshop process, to be completed no later than September 1, 2007, similar to the EDI Protocol workshop in which the Parties and other Illinois electric market participants would consider and attempt to resolve issues associated with the expanded use of the EDI enrollment processes and procedures that are currently employed for customers on RES supply to customers that elect service under the Companies' BGS-FP, BGS-LFP and RTP tariffs. This provision may be superseded in the event the Commission would order or otherwise direct Ameren and/or other stakeholders to become engaged in workshops or other like processes, to consider and attempt to resolve the aforementioned issues.

The Ameren Companies have already begun the process of honoring the MOU and will continue to do so. The Ameren Companies respectfully request that the Commission approve the MOU as the means by which to resolve the issues as and between the Ameren Companies and CNE/PES. The Ameren Companies note, however, the MOU expressly reserved the rights of the parties to debate the issues surrounding the recovery of Supply Procurement Adjustment charges as addressed elsewhere in this brief.

Finally, there may be issues not specifically identified in the MOU, or not resolved in testimony and identified as settled issues elsewhere in this brief. Nonetheless, based on the MOU the only issue remaining between these parties in this proceeding relates to the SPA.

2. Distribution Loss Multipliers

The Ameren Companies conducted a study to determine a composite set of distribution loss multipliers. This variable loss multiplier is being offered in lieu of a fixed loss multiplier. The loss multiplier intends to compensate the Ameren Companies for energy lost during the conduction of electricity across the delivery system. (See IIEC Ex. 4.0, p.3). Ameren Company witness Jones explained in great detail the results of the study, and how it affected a change in the Ameren Companies' delivery service tariffs. These changes are reflected in Section 5.B of the Supplier Terms and Conditions. (Resp.Ex.20, pp.36-37; Resp. Ex.41.0, p.24.). The use of the variable loss multiplier benefits customers because it provides for a more accurate price signal, and assigns less total energy losses to customers throughout the year. (Resp. Ex. 20.0, pp.34-38).

The only party to respond to this proposal was IIEC. Mr. Stephens agreed this approach may be a more accurate and fair way to account for system losses than the fixed lost factor method. However, he expressed concern as to the manner by which the loss multiplier may add to the complexity and uncertainty in the process of buying and selling power. (IIEC Ex. 4.0, pp.2-9).

Mr. Jones, through discussion and example, explained that the financial exposure to customers under either the fixed or variable loss multiplier mechanism was quite minimal but that nonetheless customers continued to greatly benefit. (Resp. Ex. 41.0, pp.21-24). It is our understanding IIEC does not oppose the use of the variable loss multiplier and, indeed, the record supports its approval by the Commission.

V. RESPONSES TO COMMISSIONERS' QUESTIONS

Dated: August 23, 2006

Respectfully submitted,

CENTRAL ILLINOIS LIGHT COMPANY
d/b/a AmerenCILCO

CENTRAL ILLINOIS PUBLIC SERVICE
COMPANY d/b/a AmerenCIPS

ILLINOIS POWER COMPANY d/b/a
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PROOF OF SERVICE

I, Laura M. Earl, certify that on August 23, 2006, I served a copy of the foregoing Response by electronic mail to the individuals on the Commission's Service List for this Docket.

By: /s/ Laura M. Earl
Attorney for the Ameren Companies